ENERGY AND ELECTRICITY
Conference

CONFERENCE PROCEEDINGS

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ENERGY AND ELECTRICITY CONFERENCE

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NOTES FOR AN ADDRESS

BY

MARIE GIBEAU
MEMBER OF PARLIAMENT FOR BOURASSA

ON BEHALF OF

THE HONOURABLE JAKE EPP
MINISTER OF ENERGY, MINES AND RESOURCES CANADA
AND MEMBER OF PARLIAMENT FOR PROVENCHER

TO THE

CONFERENCE OF
THE CANADIAN ENERGY RESEARCH INSTITUTE

MONTREAL, QUEBEC
JUNE 4, 1990

Check against delivery

Canada

Introduction

Good afternoon, ladies and gentlemen.

It is a pleasure to be here today to take part in this conference. You are discussing a very important and very complicated part of the work of your industry. Planning electricity needs is difficult. You have to make forecasts on a host of variables: everything from population fluctuations and economic growth, to technological advances and social attitudes. And as if things weren't complicated enough already, a new and very substantial source of change is upon us. I am speaking, of course, of the dramatic rise in the prominence of the public's environmental concerns.

Finding ways to maintain and enhance our well-being without harming the environment is at the top of the national agenda for the 1990s. This will make your jobs more complicated. A reliable supply of energy is fundamental to our lives. Yet, we know that the ways in which we produce and consume energy contribute to some of our most pressing environmental problems. All the traditional sources of energy we have come to rely on are being questioned.

Electricity is an important and growing part of the energy picture. Responsibilities for this sector are shared between the federal and provincial governments, but it is the provinces and the utilities that have to make the fundamental decisions on electricity supply and pricing.

Society will continue to ask those of you engaged in the electrical utility industry to do what you have always done, and to find economically sound ways to keep the lights turned on. After all, we have a very electricity intensive economy. But now you will be expected to meet our demand for electricity in an environmentally sustainable fashion. You have a role to play in the major global quest of our era. There will be real change in the way we do things, and in the way we approach decisions. I think we are in for exciting and satisfying times. Today, I want to speak about the roles I see for each of us -- the federal government and your industry -- in meeting these challenges.

The Environmental Agenda

Momentum to deal with environmental challenges has built with astonishing speed. There is disagreement as to how dramatic changes in the environment will be, how quickly they will occur and how the effects will be felt. But there is broad and deep public consensus that changes to the atmosphere threaten our future. I know leaders have developed a better appreciation for the need for stewardship of the planet. Clearly, the public's strong expectations are the reality politicians must act upon.

We are making progress. All of the provinces east of Saskatchewan have agreed to major reductions in the sulphur and nitrogen oxide emissions that cause acid rain. We look forward to reaching an agreement with the United States soon on controlling air quality in our shared atmosphere.

As many of you are aware, the Government of Canada is presently engaged in a period of extensive consultation on environmental policy. These consultations are providing input to the formulation of a national environment strategy. That strategy, the Green Plan, will be announced later this year. It will be the foundation for Canada's move towards an environmentally sustainable economy.

Let me outline briefly what the federal government's role has been in the electricity field, and how these new environmental imperatives are affecting that role.

In Canada, electricity is increasingly the energy form of choice. It now makes up about one quarter of all energy consumed in Canada. Although we will pursue every opportunity for greater energy efficiency, our projections indicate that our energy needs will grow over the next decade. And electricity will expand its share of the supply. Even with our best efforts at conservation, we will need new generating capacity. That is where the tough decisions begin.

Virtually all large-volume sources of electricity carry environmental risks. Hydroelectric projects create reservoirs, flood forests, and disrupt river systems. The burning of fossil fuel produces emissions that contribute to acid rain, increased concentrations of ground-level ozone, and the greenhouse effect. The nuclear industry faces its own environmental controversies.

We are struggling to understand the options. We need more knowledge of the relationship between our activities and the effects on the atmosphere and the ecosystem. As that knowledge becomes available, our choices will change. So the last thing we want to do at this time is to limit our alternatives. In the sixteen months Mr. Epp has been Energy Minister, one of his major goals has been to keep our energy options open and available.

Keeping Energy Options Viable

In Canada, we are fortunate to have a large hydroelectric capacity. It supplies close to 60 per cent of our electricity. Although dams and reservoirs alter the landscape, hydroelectricity does enjoy acceptance as a non-polluting form of energy. Certainly, we will continue developing economic hydroelectric potential. But this is a limited resource. Many of the best sites have already been developed, and, in this vast land, not all regions are blessed with tumbling rivers. Also, rainfall fluctuates from year to year. So we need to have other sources available.

Coal is Canada's largest fossil energy resource. This government has worked to make coal more environmentally acceptable and thus ensure it will continue to fulfill its role in Canada's energy mix. EMR devotes upwards of 130 people and a budget of more than $16 million annually to the research and development of coal technologies. Greater efficiency in the production of coal-fired electricity will be an important objective.

Some regions of Canada rely heavily on nuclear-generated power. Candu reactors, drawing on Canada's abundant uranium resources, provide about half of Ontario's electricity and 40 per cent of New Brunswick's. Our strong support for our nuclear endeavours is obvious from our recent decision to restructure Atomic Energy of Canada Limited.

The federal cabinet, Ontario Hydro, and the provinces of Quebec and New Brunswick have made firm and, in these times of budget squeezes, impressive financial commitments. They have pledged to increase and maintain their funding to AECL's research and development programs for seven years. The revitalized nuclear industry is proceeding to finalize the design of the Candu 3 reactor -- a smaller, 450-megawatt unit. We are leading the world in the development of this size of reactor, which will make nuclear power more accessible to a wider range of utilities.

As part of the effort to keep the nuclear option open, we have backed AECL's research into long-term disposal of radioactive fuel wastes. AECL's proposed concept is to bury reactor wastes in the very old and stable rock of the Canadian Shield. The research that has gone into this concept represents an investment of $400 million over the past decade. Another important step is now underway. An Environmental Assessment Review Panel has begun its examination of the deep-rock disposal concept. This thorough scrutiny will include analysis by independent scientists and full public hearings. We expect this EARP review will be the most extensive environmental inquiry ever undertaken in Canada.

Natural gas is an increasingly important means of generating power, especially for peaking applications. It is also relatively clean and abundant. Shortly after my government came to office, we adopted a more market-oriented approach to the natural gas industry. We gave suppliers greater access to the transportation systems and to markets. This has led to greater availability of supply and to lower prices as well.

EMR continues to develop alternative energy sources and technologies. We support research into obtaining electricity from the wind, the tides, the sun's rays, biomass and small-scale hydro facilities.

Electricity Trade

Besides maintaining and developing a variety of means for generating power, we have worked on another facet of energy supply: the ability to move electricity around. For economic or environmental reasons, it frequently makes sense to move electricity between provinces. Ontario Hydro recently obtained an agreement to purchase electricity from a planned hydroelectric project in Manitoba. Alberta and B.C. are discussing further co-operation that will let both provinces make optimal use of their generating resources.

In the past, EMR has provided low-interest financing for interconnections between regional electrical networks. At present, Minister Epp is awaiting a response from the National Energy Board to his request that it identify measures to encourage greater interprovincial co-operation in electricity planning.

We recognize the advantages of electricity trade with the United States. Our seasonal demand for power for winter heating dovetails with the needs of our neighbors to the south for air conditioning to beat the summer heat. My government has opened up opportunities for transnational trade. The Canada-U.S. Free Trade Agreement enables Canadian suppliers to offer secure contracts to customers in the United States. And Bill C-23, which was recently passed by Parliament, streamlines the regulatory process for the approval of new electricity exports.

Action on the Environment

Mr. Epp has been talking about his commitment to keep energy options open. There is another key aspect to his mandate as Energy Minister. Nowadays, everyone seated around the cabinet table makes environmental responsibilities a priority.

Mr. Epp has been meeting with the provincial and territorial energy ministers to discuss what we can do about atmospheric change. We have an intergovernmental task force working on the question. As well, Canada is a leader in the push for international agreements on global environmental concerns. An example is the 1987 Montreal Protocol on Substances that Deplete the Ozone Layer.

When the federal environment strategy is announced later this year, it will give fresh impetus to all of these efforts. The Green Plan will be a call to action. A central feature will be the issue of greenhouse gas emissions and targets and schedules for their reduction. Any targets, and other initiatives, announced in the Green Plan will be established through extensive consultations with the public and other interested parties. The discussion paper released recently, and the public consultation meetings now being conducted, are important focuses for building consensus. At the same time as the Green Plan exercise is underway, we are working with provincial governments to develop a comprehensive national action strategy on climate change by this Fall, as was announced in Kananaskis.

The discussion paper mentions numerous possible directions. These possibilities are not commitments, or even the government's preferred options. They are intended only to stimulate discussion. But I would like to give you a sampling of the ideas that have been raised. They include research and the demonstration of new technologies; environmental audits for government and private sector organizations; the strengthening enforcement of environmental laws; appropriate regulations, and management programs for emissions.

So what are those of you here today to make of all this? The message is simple. We are talking about real change. The status quo of the past is now ancient history. We are facing our environmental responsibilities now and the effort is going to intensify rapidly.

This brings me to the question of the electric power industry's role in meeting the challenges of the environment. First of all, I hope you will help sustain current energy options. As, I mentioned earlier, Ontario Hydro, Quebec and New Brunswick, and some private sector companies will join in the funding and activities of AECL. Moreover, some of the utilities represented here have joined with EMR to launch demonstration projects for clean coal technologies.

Perhaps most important, though, we will all have to change the ways in which we make decisions. To start with, we will have to broaden the selection of options, by looking outside of the traditional ways of doing things, to seek out and evaluate imaginative and creative alternatives.

Demand-Side Management

I am impressed by the Demand-Side Management programs of some utilities. BC Hydro pioneered in this field. Its DSM program has included extensive education and advertising campaigns aimed at all sectors: residential, commercial and industrial. There are rebates for the purchase of high-efficiency motors, appliances and lighting. The utility is giving away free insulating blankets for residential hot water heaters, and is running a trial project to buy old, inefficient refrigerators and get them out of operation.

Ontario Hydro expects to spend between two and three billion dollars on demand management programs in this decade. Its aggressive efforts, which you will be hearing more about tomorrow, are targeted at all sectors and involve intensive educational campaigns, a variety of rate and rebate incentives, and extensive research.

It is appropriate -- and absolutely necessary -- that the leadership in these areas come from the utilities. You, the utilities are the experts with the sophisticated knowledge of electricity systems. You know what works within your circumstances. You best understand your customers, what changes are possible in meeting their needs, and how their consumption patterns can be altered most effectively. In other words, you know your business. The responsibility is your's to keep the lights on AND to do so in an economical and environmentally responsible fashion.

The Government of Canada will do its part. EMR has dedicated upwards of $200 million during the next four years for research and development that will advance energy efficiency.

There are a Variety of Demand-Side Management schemes being discussed, developed and tested around North America and elsewhere. For example, there has been experimentation with demand-side auctions. These are akin to the calls that some Canadian utilities have issued for independently-produced power. But instead of asking for supply, the utility offers payments, or rate reductions, to those who can deliver the biggest savings in consumption. I am not advocating this scheme -- or any others. But I am putting a question to you: Which ideas are worth trying out in your jurisdictions? You are the experts. Be creative. Show us what the possibilities really are.

Industry Leadership

Many of you in the electric power industry undoubtably feel you are already subjected to a lot of demands, questioning and scrutiny. Well, like it or not, that is going to intensify. When you present plans, you will have to be able to show that you have seriously considered all the alternatives. Increasingly, your customers, the general public, governments, environmental review panels and regulatory bodies are going to be asking: Have you weighed all the options? Show us solid evidence that your plans achieve the best possible balance.

This industry has demonstrated responsibility. Your continued leadership will give you valuable credibility as we deal with the new realities of the 1990s.

Much remains to be done. Governments and industry will be working together closely. Your industry's leadership and participation will help alleviate the environmental concerns associated with energy supply options, such as fossil fuels and nuclear energy. Working together, government and industry can jointly set priorities for scarce research and development dollars. I urge you to continue to boldly seek alternatives, to evaluate and experiment.

Conclusion

For Mr. Epp, beyond the activities of his department, he remains committed to retaining the options for meeting future energy needs. He will continue to insist on careful analysis of environmental proposals involving energy to ensure the economic and social trade-offs are understood and properly considered. As he works to implement the government's energy and environment strategies in an economically feasible way, he will seek the advice and co-operation of the electric power industry, and will give attention to your concerns and proposals. Together I know we can stay abreast of rapidly developing events.

These are challenging times. We do hold the future in our hands. So much is at stake; so much depends on our wisdom and our courage. But there is the opportunity for creativity and satisfaction. I hope that when we pass the torch to the next generation, we will be able to say we faced the tough decisions in good faith and gave our very finest effort.

Thank you.

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CONFERENCE SUMMATION

Presented by

Milan Nastich

Vice Chairman

AGF Management Limited

Toronto, Ontario

ENERGY AND ELECTRICITY CONFERENCE

MONTREAL, QUEBEC   JUNE 3-5, 1990

As I sat listening to the various experts talking, I tried to establish a set of criteria: a basis under which I could judge the relevance of their views. And I decided I would start by giving my view of the context of the society in which we are living; and then, using that context, discuss each of the papers of this two-day conference.

The first phase of my context relates to my experience that the public today is very distrustful of large institutions--governmental, private, and corporate. This suspicion, which in many cases has been justified by the corporations and the governments failure to meet the expectations of the public, has resulted in the rise of special interest groups who have particular expertise in particular areas and have been able to mobilize this latent distrust and cynicism to create problems for all institutions.

The public has also become much more oriented toward local issues because they can establish in local communities much more control over how they think their lives should be handled. The public in the last decade has become more inclined to stop a project rather than let it go ahead. I have to come to that conclusion because I have been seeing since I left Ontario Hydro whole series of major projects in Ontario for which there was a tremendous public need. Waste management is an example. And yet, you can see the public in all areas of the province fighting desperately to avoid having that waste management facility located anywhere near them. And it is not only that they do not want it near them; they are arguing that it is not needed which tells you something about the depths to which the public can go to avoid a problem and to indicate their distrust of the technology of the governments or the institutions who are pushing these ideas.

Another aspect of today's public is an increasing sensitivity to the environment. We have seen that in the discussions here today. Almost every speaker, one way or another, dealt with the environment as a major factor in whatever area of the utility business they were talking about. Increasingly customers want good customer service, high reliability, and they do want a minimum of fuss in their lives. They want an integrated approach to their life. When they go to the bank, they do not want any problems. When they turn on the light switch, they want the lights to be there. And this is almost a direct contradiction to their response when a utility proposes a new transmission line or we need a new generator or whatever. Their response is first prove you need it and then secondly, can you put it somewhere else.

What you have is a public that is somewhat cynical, has found reasons for the cynicism, does listen very strongly to special interest groups because it sees those groups as furthering their interests. Not necessarily true, but that is the perception.

I would like to take that as a starting point and go through the program that you have had today and yesterday, and relate that to my defined context. This may give some reasons why some of the programs you propose are not going to go through very easily and why some of the other programs are going to go through very easily.
First, there are the regulatory aspects relating to the utilities. I found the speeches by Dr. Stalon and Dr. Kwaczek the most fascinating parts of the conference. Others were great, but I think this was the area in which the utility business is in real trouble. It is the area in which the public's distrust of institutions such as the utilities and others is focused. And they very beautifully and clearly outlined the logic and the possibilities that we have in improving the regulatory processes. The regulatory process is coming to a dead end. One of the factors that we are all facing is an aging infrastructure. Not only in electric utilities; but our waste management, our sewage, our water systems, our transportation systems are all going to require enormous sums of capital. They are going to be very disruptive to communities. And the regulatory process that we now go through, the environmental process that they will have to go through, will be so cumbersome and so non-productive that at some point the public will be changing their minds. So I suspect there will be somewhat of a radical reform but not until there is a considerable amount of upset and disruption through the inability of governments and institutions to build the infrastructure on which our country is built.

I would like to have heard much more discussion of trends in the regulatory area because if you solve those problems, you will find much of your difficulty will diappear. I found that section very instructive, very illuminating, and would like to have heard more.

The second subject was again related to the environment and the need for trade in electricity. Electricity trade is one way in which a Utility in one area can share benefits with another and the key to that trade is the transmission network. And that is one of the more difficult, more intractable issues because it is not localized. It is seen by the public as either benefitting somebody somewhere else or not benefitting anybody but creating real troubles for them in their own local area. And it is here that the Utilities are going to continue to find difficulties. I do not know of any answer, but I do know that the electricity trade is important to utilities to maximize their efficiency. But as yet there is no real answer.

Demand management, which was also an interesting session for me, is the first one in which you are starting to ring the right bells with the public. The bells are conservation, prudence, lack of waste, and trying to make the best out of what you have. And to me that is a tremendous sign of hope for the utilities industry if you can start to convince the public that you are really serious about demand management. That you really are doing it for the reasons that Dane MacCarthy indicated. That it is a good thing. It is going to save money, save resources, and just generally be beneficial to the society. You will have started to build trust among the public which will help when you try to get new capacity in whatever form that takes.

So demand management, starts to ring the right bells for the utility industry. And I would hope that this effort which is just starting is a serious and sustained effort, because nothing would be worst for you or the public both if as a result of difficulties, of budget constraints, the demand management side of the utility business falters or is allowed to falter.

The next area which again rings bells with the community is non-utility generation. And the reason is it is local. It is being done by private enterprise which tends generally to have a better reputation among the public than governments (I am speaking in the Canadian context here). And it also can be shown to be manageable, human-sized, and to have many of the good things that the public expects. Even though it will, never be a major portion of the new generation, it will be large enough to be measurable and will indicate to the public again that the utilities are interested in every possible option to give them low cost and effective energy.

The next series of papers started to move in what I call the hard areas of the utility business which is gas-fired, coal-fired, nuclear plants-- the physical capacity additions. I think that those will likely have to be used, as one speaker said, in a balanced way because as one of the participants indicated that natural gas cannot solve all the problems. We know the opposition to nuclear power, so that a balanced approach to this side of the energy equation is very important; but it must be preceded as I have said before by demand management, by non-utility generation, by the whole ethic of conservation, efficiency and prudence.

The part that I found very heartening at the end was the hydrogen technology. Now I do not know about you, but I was starting to get sold on it. I was not sold when I was at Hydro because I had propositions given to me there about hydrogen and the more I looked at it the more I thought it was for some future chairman rather than me. But as I listened to Mr. Champagne, I could see that this is another kind of a fuel which if it could become real, rings the right bells with the public. He outlined all the reasons for it. I know the technological problems, but certainly the utility industry is a technological industry and if there is anything that we are strong at, it is in bringing new developments into being.

So all in all, I felt at times optimistic about the utility business and at other times pessimistic about the utility business. Where I am optimistic as a result of these speeches is that the technical and business sense of the utility industry is still strong. It seems to be well balanced. It seems to understand where it is at. Where the industry is in trouble is in the governance issue as I mentioned before. We have a problem in convincing the governments who are our masters (again in Canada) and the public that we really are interested in them and are not just building large plants and large transmission lines because they happen to be something that we do well.

So I would like to say that I enjoyed this conference. I had not realized I could learn as much even after four years away but I did. And I want to thank everybody here for giving me the chance to expound on some issues. Thank you very much.

CANADIAN CAPACITY REQUIREMENTS IN CONTEXT

Presented by

Morgan MacRae
Director, Coal and Electricity
Canadian Energy Research Institute
Calgary, Alberta

Presented to

Energy and Electricity: A Conference on Electric Power Planning in the 1990s

Montreal, Quebec
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INTRODUCTION

Good morning ladies and gentlemen.

I have entitled my presentation today Canadian Capacity Requirements in Context as I would like to discuss some of the factors affecting forecasts of future electricity demand and the impact of forecast uncertainties on new electrical generating requirements.

To some extent, my presentation will rely on findings presented in a study published late last year by the Canadian Energy Research Institute entitled Critical Issues In Electric Power Planning in the 1990s.

(Slide - Critical Issues)

CERI's study of Critical Issues in Electric Power Planning addressed a number of strategies that utilities might take to enhance planning flexibility and promote greater efficiency in the production and end-use of electricity. These areas are non-utility generation, demand-side management and electricity trade.

Our focus on the need for greater efficiency and flexibility stemmed from our analysis of the implications of growing public pressure for more stringent environmental controls and the impacts this would have on exacerbating demand uncertainty and limiting supply responses available to utilities.

Environmental pressures and planning uncertainties will shape the way that utilities, regulators and electricity consumers respond to the supply challenges of the 1990s. To address strategic planning implications for Canadian utilities some of the key questions that must be addressed include: 1) what are some of the factors affecting future demand; 2) how uncertain are demand forecasts; and 3) what is the expected magnitude of new supply requirements?

I would like to turn briefly now to some of the major factors which will influence future capacity requirements and which will guide the evaluation of utility responses required to meet these requirements. I hope this background helps set the proper context for my presentation of a number of illustrative forecasts of Canadian capacity requirements for the coming decade.

RECENT TRENDS AND STRATEGIES

(Slide - Recent Trends)

Electricity demand is being pulled by two general but competing forces. In one direction, Canada's economy has become more energy efficient in recent years and this trend will continue, motivated by economic, environmental and technological forces.

Canada's economy, on the other hand, has become more electricity intensive.

(Slide - Per Capita Electricity Consumption)

Electricity now accounts for almost one-quarter of all energy use in Canada, as opposed to just 18 percent only ten years ago.

While new technology often promotes energy efficiency, it also contributes in many circumstances to growth in electricity intensity. It is far from apparent which force will exert the more decisive impact on electricity consumption in the coming decades.

The push and pull of economic and technological forces will continue to exert major impacts on the uncertainty associated with forecasting future electricity demand. Moreover, environmental pressures will accentuate this uncertainty.

For example, actions taken by industry to control its emissions will result in greater use of electrotechnologies and greater demand for electricity. However, stricter environmental regulations could also force some companies out of business and, thereby, reduce the demand for electricity.

An important challenge facing Canada's electric utility planners is how to reduce and plan for demand uncertainty--gathering more accurate and timely information and improving forecasting techniques is one strategy. Utility programs which allow more flexibility to respond to unpredictable demand developments are also needed.

To enhance flexibility, for example, utilities are examining generating facilities such as combined cycle plants or natural gas-fired units that take less time to construct than large hydroelectric stations and nuclear power plants.

Greater use of interprovincial electricity trade, demand-side management and non-utility generation are also gaining increasing support as ways of enhancing utility flexibility in the face of more uncertain electricity demand growth.

ENVIRONMENT PRESSURES ON DEMAND/SUPPLY

Recently, actions to reduce environmental emissions have erupted as a major factor affecting electricity demand and supply.

(Slide - Environmental Pressures)

In fact, for the foreseeable future, initiatives directed to controlling SO_2, NO_x and CO_2 seem destined to dominate electric utility supply- and demand-side planning.

What are some of these pressures and how are utilities responding?

Initiatives to Limit Acid Gas

The first major environmental initiative was Canada's signing of a SO_2 Protocol in 1985 and the enactment of the Canadian Acid Rain Control Program, where Canada's seven easternmost provinces (Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland) will reduce their SO_2 emissions from roughly 4.5 million tonnes in 1980 to 2.3 million tonnes in 1994.

In 1988, the Canadian government signed a second Protocol directed to reducing NO_x emissions and in early 1990, a Draft Management Plan aimed at solving ground level ozone problems was released for public review.

Draft Plan recommendations for NO_x/VOC control for Canada's electric power sector include:

- programs for demand-side management and energy efficiency standards;
- staged implementation of New Source Performance (NSP) standards across Canada; and
- more immediate standards in the Lower Fraser Valley (LFV) and Windsor-Quebec corridor (WQC), owing to the severity of regional ozone episodes in these areas.

By 2005, NO_x emissions from electricity production are projected to fall 127 kt -- almost 10 percent below 1985 emissions. Demand-side management and new energy efficiency programs are forecast to account for a full 30 percent of these reductions. Electric utilities in Ontario, Alberta, New Brunswick and Saskatchewan represent almost 95 percent of NO_x reductions projected in the Draft Management Plan.

Utility Response to Acid Gas

(Slide - Utility Response)

Owing to the current status of the Draft Management Plan, it is difficult to say what combination of supply- and demand-side programs electric utilities will find to be most cost-effective for NO_x reduction in the 1990s. However, utility actions to reduce SO_x seem indicative of the kinds of actions that might be taken for NO_x.

To reduce SO_2 emissions, Canadian utilities have switched to low sulphur coals and post-combustion control technologies such as Fluidized Gas Desulphurization (FGD). Many utilities are also examining advanced clean coal technologies such as fluidized bed combustion (FBC) and Integrated Gasification Combined Cycle (IGCC).

In addition, some utilities are actively expanding their demand-side management and non-utility generation programs and some utilities are exploring greater electricity trade with neighbouring provinces.

For example, Ontario Hydro plans to retrofit FGD at two 500-megawatt coal-fired units by 1994. Depending on load growth, many more FGD retrofits may be required. For the long term, Ontario Hydro's plans include load management and conservation, purchases from neighbouring utilities (such as Manitoba), nuclear power development and the development of IGCC plants.

Formulating A Response to CO_2

(Slide - Response to CO_2)

While acid rain seems manageable, one of the greatest uncertainties facing electricity planners is how to respond to increasing public concern with global warming. What initiatives have been taken and what actions are being examined by utilities?

First, the initiatives.

In June 1988, Canada hosted a major international conference which recommended that worldwide greenhouse gases be reduced by 20 percent (2005).

In August 1989, a cross-Canada energy task force concluded that the measures it had examined would not be sufficient to attain this 20 percent reduction. In their second report (April 1990), the Task Force concluded that a 20 percent reduction by 2005 would cause significant economic dislocation and require significant changes in lifestyle.

Given the global nature of the greenhouse problem and the scientific uncertainties related to global warming, the Task Force suggested that the prudent course of action would be to take steps towards the stabilization and eventual reduction of carbon dioxide levels.

The problems faced in formulating a response to the CO_2 question are aptly depicted in Environment Canada's recent Green Plan, A Framework for Discussion on the Environment (March, 1990) where Canadians are asked: how much, how far and how fast questions on a range of environmental issues spanning toxic substances to heritage resources.

(Slide - Green Plan Queries)

Questions include:

1. Should Canada commit itself to greenhouse gas emission targets? If so, on what basis should the targets be determined? Should Canada commit itself unilaterally or only as part of concerted international action?

2. What mechanisms should be used to achieve the reductions--environmental taxes, tradeable emission permits, support for new environmental technologies, etc.?

(Slide - Green Plan Queries)

3. What role should nuclear energy and hydroelectric power play in reducing greenhouse gases? What role should energy efficiency and alternative energy play?

4. What additional measures should be taken to reduce acid rain beyond 1994?

The key uncertainty is: what action plan will the federal government eventually set in motion and how will it affect our forecasts of electricity demand and impact our generating supply options?

Limits to CO_2 Response

(Slide - CO_2 Response)

On the utility side, strategic responses to CO_2 stabilization and reduction are under investigation by a number of Canadian utilities and by the Canadian Electrical Association. CO_2 removal for enhanced oil recovery and technologies that appear capable of offering significant improvements in generating efficiency, particularly IGCC, are being seriously assessed by utilities across Canada.

Improving the efficiency of energy consumption is also under active investigation. For example, Ontario Hydro plans an aggressive DSM program, which could result in as much as 4000 MW of electricity savings by the year 2000.

The recent NO_x Draft Management Plan, which calls for DSM/efficiency programs accounting for 30 percent of projected NO_x reductions by 2005, has also prompted greater utility interest in demand-side programs across Canada.

Some of Canada's remaining hydroelectric potential (50 000 MW) may emerge as an attractive alternative to expansion of fossil-fuelled generating capacity but strong lobbying against major new hydroelectric facilities makes hydro less attractive than in the past. This resistance is compounded by the significant right-of-way requirements for transmission links from Canada's North and the attendant concerns with both the aesthetic impacts and the potential adverse health effects of high voltage transmission lines.

Nuclear power is also an option but considerable opposition to further nuclear power development persists in many parts of Canada because of expressed concerns over the safety and disposal aspects of nuclear power generation.

For the foreseeable future, it appears that a combination of fuel switching and improved efficiency at both the production and end-use stages will be required, although the absence of a formal agreement on CO_2 reductions limits meaningful discussion of utility action plans.

CONCLUSIONS

Summarizing to this point--environmental initiatives, particularly CO_2, make forecasting electricity demand even more difficult than it has been in the past. Until there is a better understanding of the cost-effectiveness of supply- and demand-side strategies and until a definitive call on CO_2 reductions by electric utilities is made, forecasts of electricity demand and new electrical generating capacity are very uncertain.

THE SUPPLY CHALLENGE

Nonetheless, it is fundamental that we have an understanding of the relative magnitude of the supply challenge faced by Canada's electric utilities so we can examine cost-effective strategies for new generating supply.

(Slide - Capacity Additions by Province)

The implications of forecast demand uncertainty are clearly brought home in forecasts presented in CERI's Critical Issues study. In this study, we examined forecast capacity requirements under two reasonable scenarios of future electricity demand in Canada.

In the utility base case (2.4 percent average annual growth), a total of over 9200 MW of new capacity would be required for Canada as a whole by the end of the century. Adding 14 500 MW of capacity from projects already committed results in total capacity additions of some 24 000 MW by the turn of the century.

In our high demand scenario (3.5 percent average annual growth), the amount of uncommitted required capacity more than doubles from the base case to just under 23 000 MW. Adding 14 500 MW from committed expansion projects results in a total estimate of new capacity additions of over 37 000 MW by the end of the century.

The implications of forecast uncertainty to future supply requirements are noteworthy--while there is only a moderate difference of one percentage point between these two demand scenarios, the difference between the capacity additions required in the two cases is very large. **A slight increase in demand growth is magnified into a substantial difference in future generating capacity requirements.**

Historical Comparison

It is also interesting to compare projected capacity requirements to that experienced in the past.

(Slide - Electricity Demand Growth by Decade)

As shown in the figure, average annual growth in electricity demand expected over the rest of this century--even in the higher of the two demand scenarios--is quite modest by historical standards. A generally slower rate of economic growth by historical standards and increases in energy efficiency imply that electricity demand growth will generally be slower than has been experienced in the past.

Unfortunately, this does not mean that Canada's electric power industry will face less supply pressure as a result. Because the size of Canada's electricity system has increased so greatly, even modest rates of demand growth will be reflected in relatively large absolute requirements for new generating capacity.

(Slide - Yearly Capacity Additions, 1920s - 1990s)

For example, the base demand scenario (including firm export opportunities) would result in the addition of some 2700 MW of new capacity per year between now and the year 2000--more than in any period of Canadian history, with the exception of the 1970s. As shown at the far end of the graph, utility data recently compiled by Energy, Mines and Resources Canada shows a more moderate average growth for the 1990s of 2200 MW per year.

If, demand growth were to follow the high scenario, average increases in generating capacity of nearly 4000 MW per year would be required.

The magnitude of these projections emphasizes the need for utilities and policy makers to work together to develop supply and demand strategies which maximize flexibility and minimize environmental impacts.

CHALLENGES FOR THE 90's

To conclude, the decade of the 1990s brings a new set of challenges. Foremost among these is the environment. The pursuit of greater efficiency and system flexibility in the face of tighter environmental controls and more uncertain forecasts of electricity demand is compounded by Canada's need for major new additions to generating capacity.

I would like to thank you for the opportunity to review some of the Institute's research on electric power. I look forward to the comments by speakers later in the program whom, I am sure, will shed further light on how to address the challenges that appear on the horizon. Thank you.

CANADIAN CAPACITY REQUIREMENTS IN CONTEXT

Presented to:
Energy and Electricity: A Conference on
Electric Power Planning in the 1990s
June 3-5, 1990
Montreal, Quebec

Presented by:
Morgan MacRae
Director, Coal and Electricity
Canadian Energy Research Institute

CRITICAL ISSUES

- Strategies to promote greater planning flexibility and efficiency in production and end-use of electricity.

- Focus on efficiency/flexibility stems from public pressure for more stringent environmental controls.

RECENT TRENDS

- Electricity demand pulled by two general but competing forces:
  - Canada's economy has become more energy efficient.
  - Electricity now accounts for almost one-quarter of all energy use compared to 18 percent only 10 years ago.

- Not apparent which force will exert the more decisive impact on electricity consumption.

ENVIRONMENTAL PRESSURES ON DEMAND/SUPPLY

- SO2, NOx and CO2 initiatives seem destined to dominate electric utility supply and demand-side planning.
  - First initiative--SO2 Protocol (1985) and Canadian Acid Rain Control Program; 4.5 Mt to 2.3 Mt.
  - Second initiative--NOx Protocol (1988) and Draft Management Plan for NOx and VOC (1990).

- Demand-side management/new energy efficiency programs account for 30 percent of projected NOx reductions.

UTILITY RESPONSE TO ACID GAS

- Actions to reduce NOx uncertain at this time.

- Actions to limit SO2: coal switching, FGD, fluidized bed combustion (FBC), Integrated Gasification Combined Cycle (IGCC), demand-side management (DSM), non-utility generation (NUG) and greater electricity trade.

RESPONSE TO CO2

- June 1988 - 20% reduction of CO2 emissions.
- August 1989 - Federal/Provincial Territorial Energy Task Force report released.
- March 1990 - Environment Canada--Green Plan, A Framework for Discussion on the Environment, how much, how far, how fast?

GREEN PLAN QUERIES

1. Should Canada commit itself to greenhouse gas emission targets? If so, on what basis should targets be determined?   Should Canada commit itself unilaterally or only as part of concerted international action?

2. What mechanisms should be used to achieve the reductions--environmental taxes, tradeable emission permits, support for new environmental technologies?

GREEN PLAN QUERIES (Cont'd)

3. What role should nuclear energy and hydroelectric power play in reducing greenhouse gases? What role should energy efficiency and alternative energy play?

4. What additional measures should be taken to reduce acid rain beyond 1994?

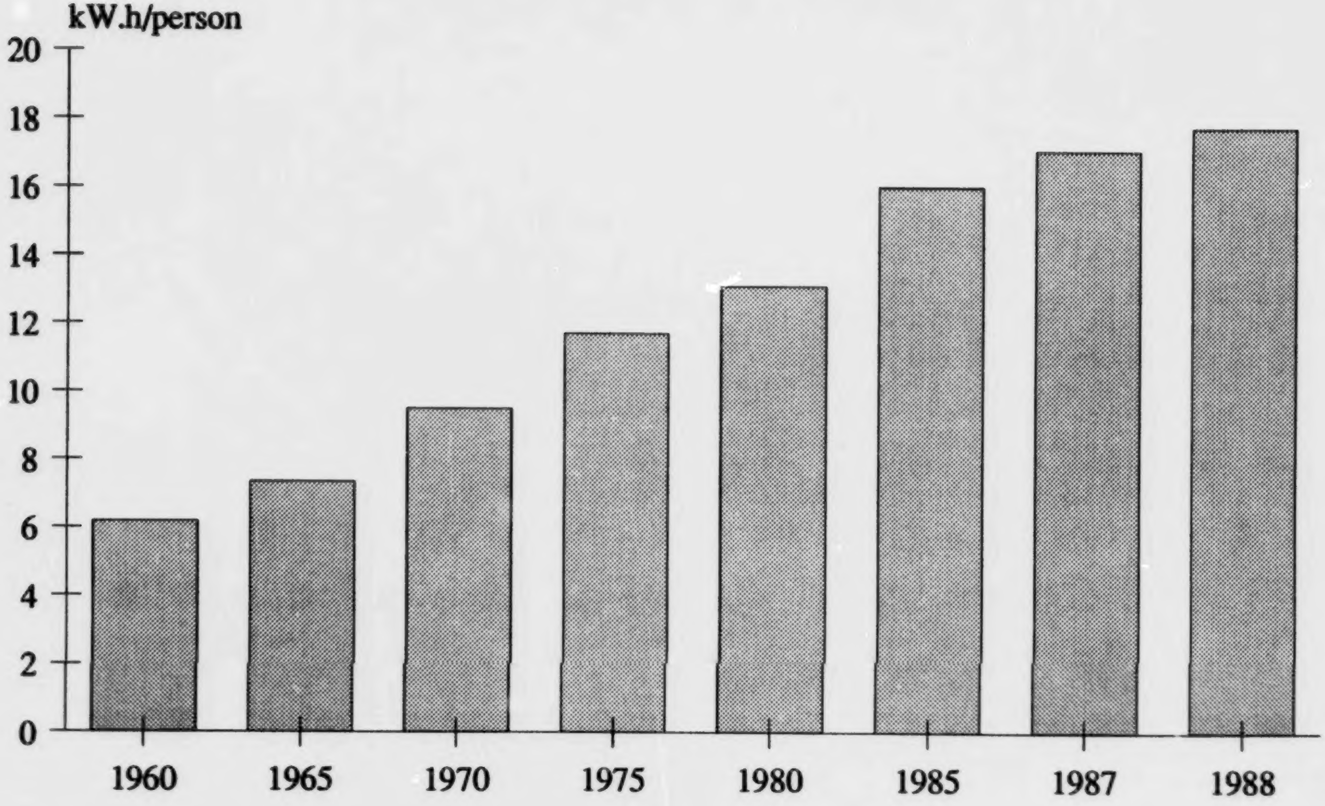
   - Key uncertainty is what action plan will materialize and how will it affect electricity demand and electricity supply options?

CO2 RESPONSE

- Strategic response to CO2 stabilization and reduction are under study by Canadian utilities and the Canadian Electrical Association.
  - CO2 removal for enhanced oil recovery
  - IGCC
  - NOx Draft Management Plan projection of 30% reduction stimulating interest in demand reduction

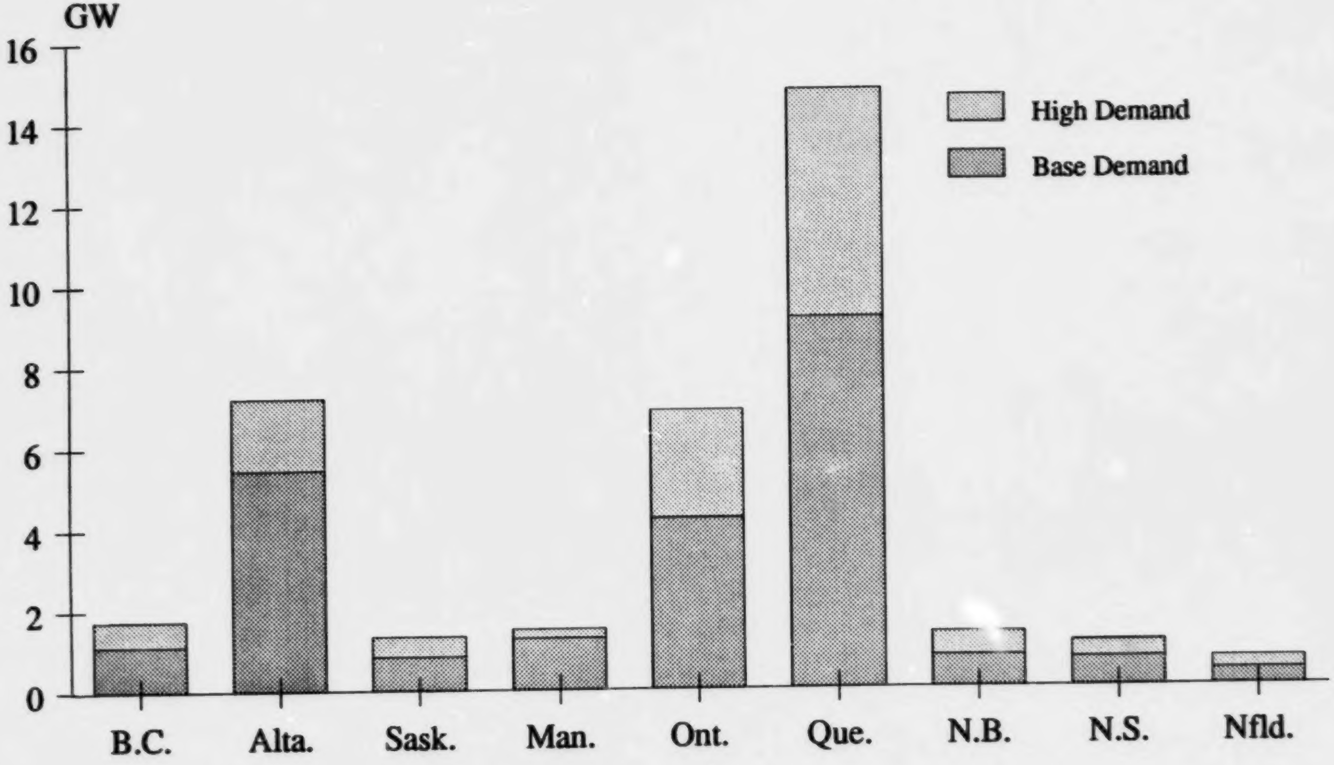
- Environmental pressures (particularly for CO2) make forecasting electricity demand more difficult and uncertain.

Per Capita Electricity Consumption
Canada, 1960 - 1988



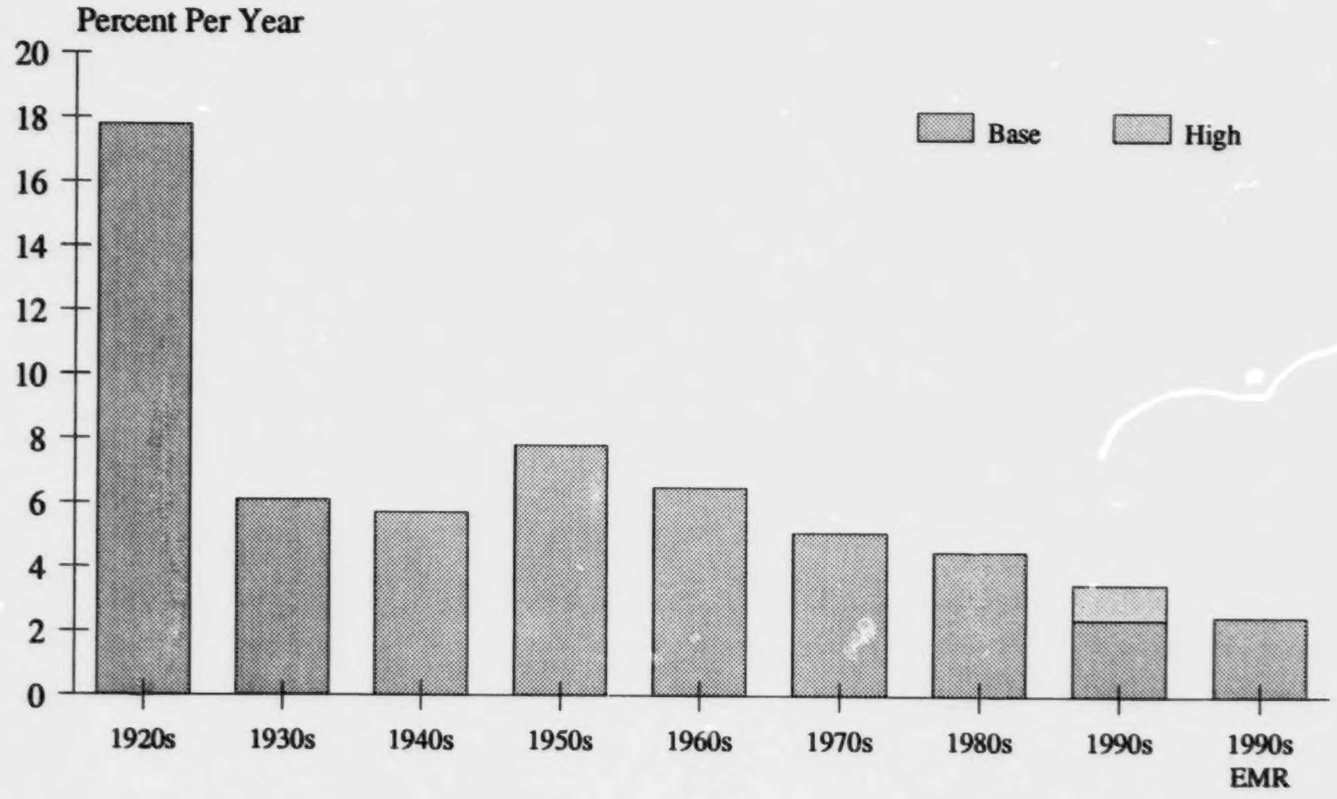
SOURCE: Electric Power in Canada,
EMR Canada, 1989.

Capacity Additions by Province
1988 - 2000



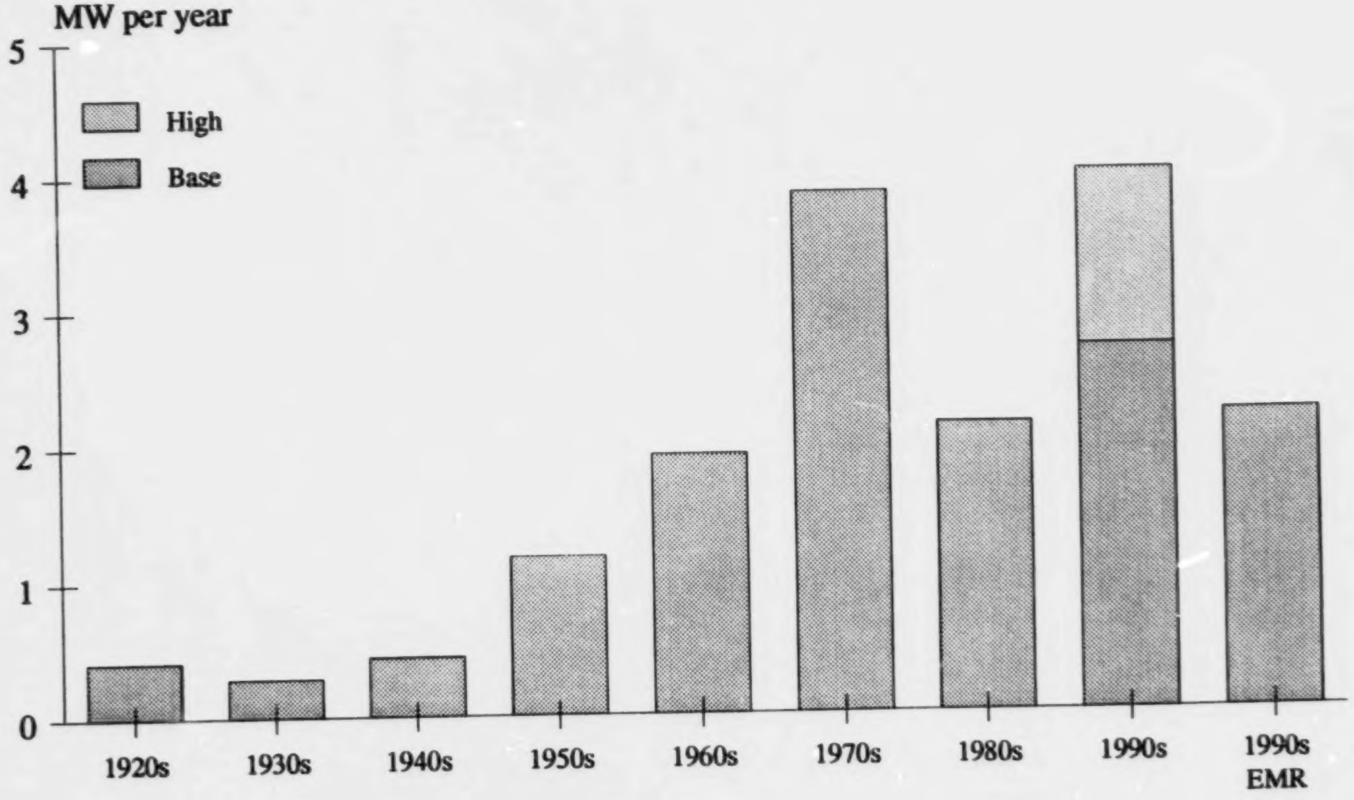
SOURCE: EMR Canada.
NOTE: Base demand includes already committed expansion projects.

Electricity Demand Growth by Decade
Canada, 1920 - 2000



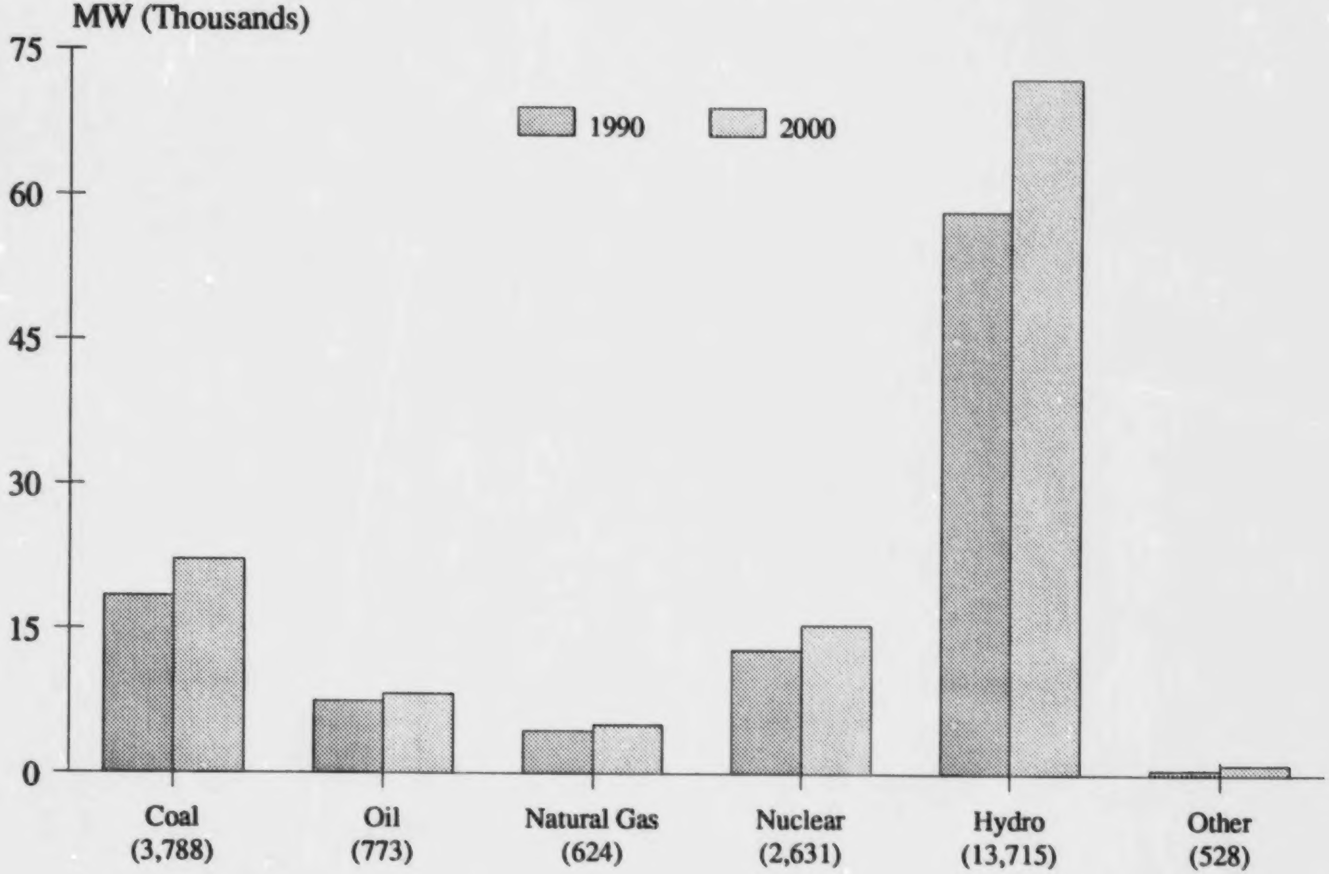
SOURCE: Historical Statistics of Canada, Electric Power in Canada.

Yearly Capacity Additions
Canada, 1920s - 1990s



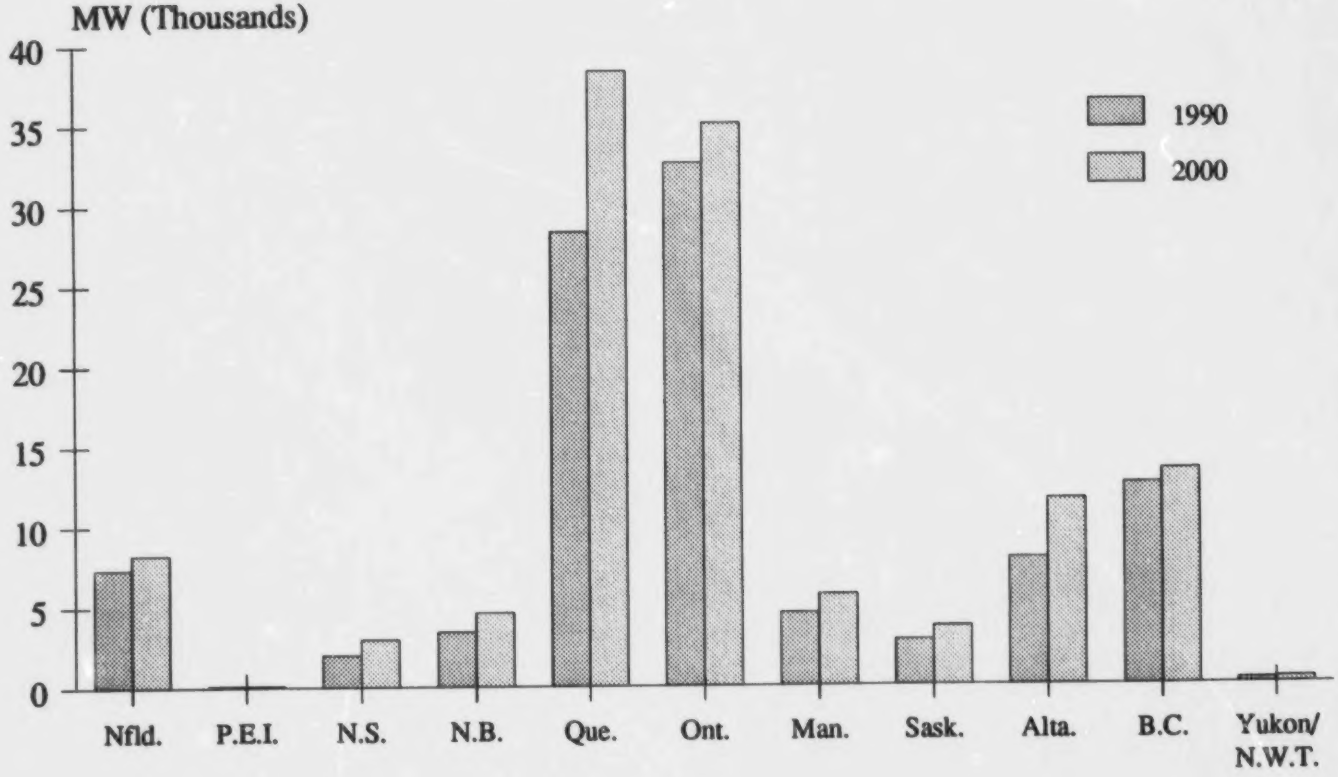
SOURCE: EMR Canada.

Installed Generating Capacity



SOURCE: Electric Power in Canada (Draft).

Installed Generating Capacity
by Province



SOURCE: Electric Power in Canada
(Draft).

Summary

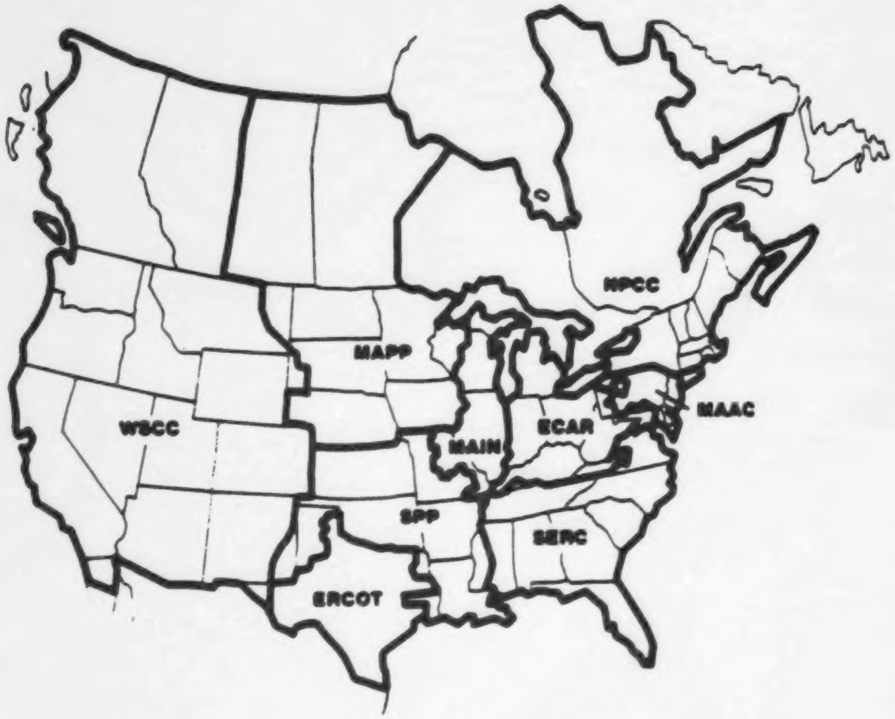
1989
RELIABILITY ASSESSMENT

THE FUTURE OF BULK ELECTRIC SYSTEM RELIABILITY IN NORTH AMERICA 1989-1998

SEPTEMBER 1989

North American
Electric
Reliability
Council

North American Electric Reliability Council



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to promote the RELIABILITY of their generation and transmission systems. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the electric systems in the United States, Canada, and the northern portion of Baja California, Mexico.

RELIABILITY, in a bulk electric system, is the degree to which the performance of the elements of that system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply (or service to customers).

Bulk electric system reliability can be addressed by considering two basic and functional aspects of the bulk electric system — adequacy and security.

ADEQUACY is the ability of the bulk electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

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Preface

The NERC Board of Trustees created the Reliability Assessment Subcommittee (RAS) in 1970 to annually review the overall reliability of the existing and planned generation and transmission systems of the nine Regional Reliability Councils.

This Summary highlights the overall assessment and key reliability issues in the *1989 Reliability Assessment*. The full report, which will be available in late September, presents:

- An assessment of electric generation and transmission reliability through 1998,
- A discussion of the key factors and issues affecting the reliability of future electric supply, and
- Detailed regional assessments of electric supply reliability, including reliability issues of specific regional concern.

In preparing this report, the RAS interviewed representatives of selected Regions and reviewed detailed self-assessments prepared by each Region, including aggregate forecasts of peak demand and planned capacity resources. The RAS appraised regional plans for future electric generation and transmission facilities, and assessed the potential effect of legislation, regulations, and governmental policies on future electric supply reliability. This report is the culmination of these efforts and reflects the expertise, judgment, and interpretations of the RAS members.

The data presented in the four figures in this Summary reflects conditions as of January 1989. Detailed background information on projected peak demands, annual energy requirements, generating capabilities, transmission, and fossil fuel requirements are presented in a companion NERC report — *1989 Electricity Supply & Demand for 1989-1998.*

Executive Summary

A reliable supply of electricity is essential to the economic well-being and security of the United States and Canada. While aggregate utility plans will support the forecast growth in peak demand, this report identifies a widespread trend of actual peak demands consistently exceeding forecasts. If this trend continues, supply deficiencies are likely by the early 1990s in the eastern half of the United States and Canada.

Several geographic areas are also identified where electric system reliability is at serious risk. Emergency operating measures, including controlled interruptions of customers' supply, will become more widespread in these areas.

Key issues and threats to reliability discussed in the report are:

Economy versus Reliability – Short-term economic goals continue to infringe on bulk electric system reliability.

Disincentives – Financial risks associated with uncertain regulatory policy are discouraging electric utilities from committing to needed additional generating capacity and transmission lines. Changing and conflicting federal, state or provincial, and local policies continue to delay the construction of critical generation and transmission facilities. These policies may ultimately erode the reliability of electric supply.

Use of Transmission Systems – Transmission systems are not planned and constructed for unlimited electricity transfers. The use of the bulk electric transmission networks to transfer electricity must be properly planned, scheduled, and controlled to maintain reliability.

Environmental Policy – Both new and existing generating capacity and transmission lines will be affected by environmental policies. Sound technical evaluations of the potential effects of proposed legislation on the environment and on electric system reliability are needed.

Non-Utility Generation – Many electric utilities are depending on non-utility generators to help supply a portion of their generating capacity. These generating units must be designed and operated to the same technical requirements as utility generators to assure their dependability and reliability over the longer term.

Specific regional reliability concerns identified in this assessment are:

ECAR – Acid rain legislation, when fully implemented, could cause the utilities in this Region to lose over 9,000 megawatts of generating capacity. This capacity would have to be replaced to maintain reliability.

ERCOT – Construction of several critical 345 kV transmission lines has been blocked resulting in inadequate transmission in the Region.

MAAC — For six consecutive years through 1988, this Region has experienced all-time record summer peak demands that have exceeded its forecast. Voltage reductions and frequent use of load management were employed to help limit peak demands during the 1988 summer. Capacity additions beyond those already planned are required in some years of the assessment period to meet reliability objectives.

MAIN — Generating capacity will be less than that required for adequate reliability in the late 1990s. Additional load management or short lead-time capacity will be needed to assure reliability. Should peak demand growth be above forecast, the timing of capacity additions will be critical.

NPCC — Peak demand and generating capacity projections indicate that additional resources beyond those already planned and committed will be required in New England as early as 1993. Unavailability of the Seabrook (1,150 MW) and Shoreham (809 MW) generating units in a Region where capacity shortages may occur in the early 1990s is of great concern. Dependency on uncommitted resources for generation adequacy puts the reliability of the electric supply in this Region at considerable risk. Frequent use of load management and selective use of voltage reductions to help limit peak demands occurred during the 1988 summer.

SERC — Use of load management will be required to maintain adequacy. If peak demand exceeds forecast, a generation deficiency could quickly develop. Further, the permitting and construction of a key 500 kV transmission line in Florida continues to be delayed requiring the operation of higher cost local generation to maintain system reliability.

MAAC-ECAR-SERC — Transmission limitations near the interfaces of these Regions restrict interregional electricity transfers. Reliability in these Regions is impaired because simultaneous needs for transmission capability cannot be met.

Because large generating units take eight years or more to build, utilities are relying on many different short lead-time options to forestall or prevent generating capacity deficiencies. These include: load management, conservation and other demand management programs, enhanced maintenance of older generating units, purchases from non-utility generators and other utilities, and short lead-time capacity additions such as combustion turbines. However, these options are not without risk.

Electric utility customers in the United States and Canada expect a reliable supply of electricity. That supply is being jeopardized in several geographic areas. Utilities and public policymakers must actively work together to thoroughly understand and manage these threats to the reliability of electricity supply in the United States and Canada.

FIGURE 1

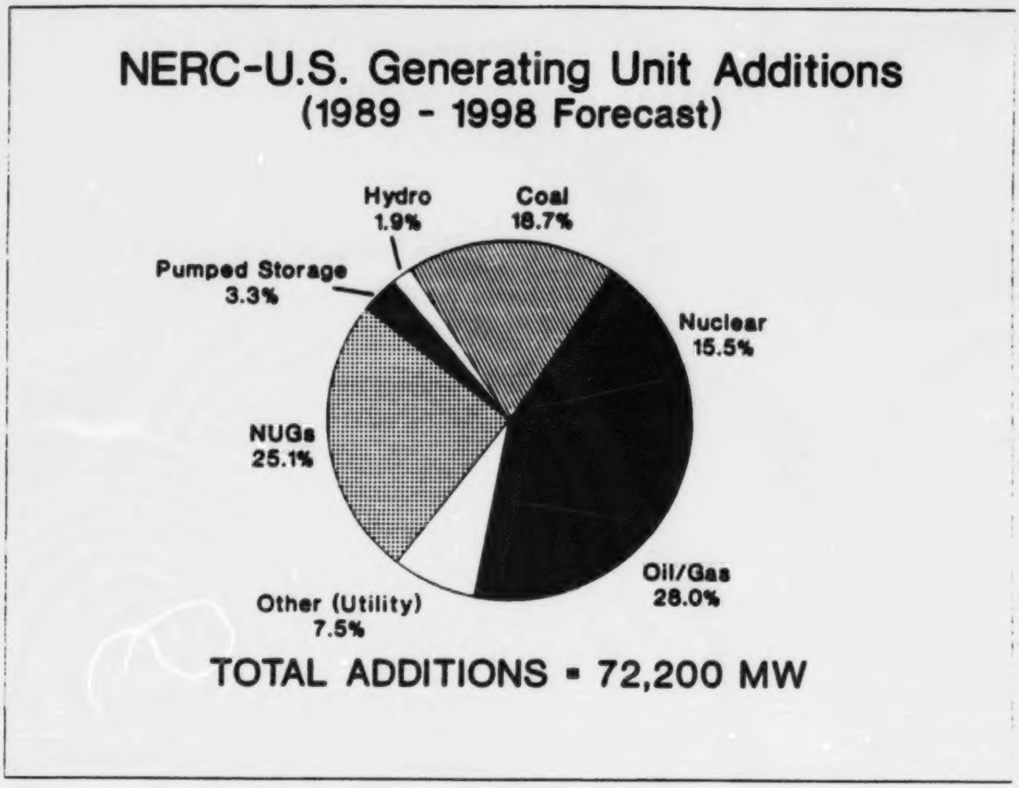

FIGURE 1: Net generating unit additions by fuel

Capacity additions of 72,200 MW are planned for NERC-U.S. over the next ten years. Coal (13,500 MW) and nuclear (11,200 MW) generating units account for 34.2% of the total. Non-utility generation facilities (18,100 MW) comprise another 25.1%. Of the remaining 40.7%, oil/gas capacity additions total 20,200 MW; other utility-owned facilities, 5,400 MW; pumped storage, 2,400 MW; and hydro, 1,400 MW.

A comparison for 1997, the last common year of the current projection and last year's projection, indicates that the total U.S. generating capacity will be about 2,400 MW higher than last year. The change is primarily due to increases in utility coal and oil/gas units and NUG units.

FIGURE 2

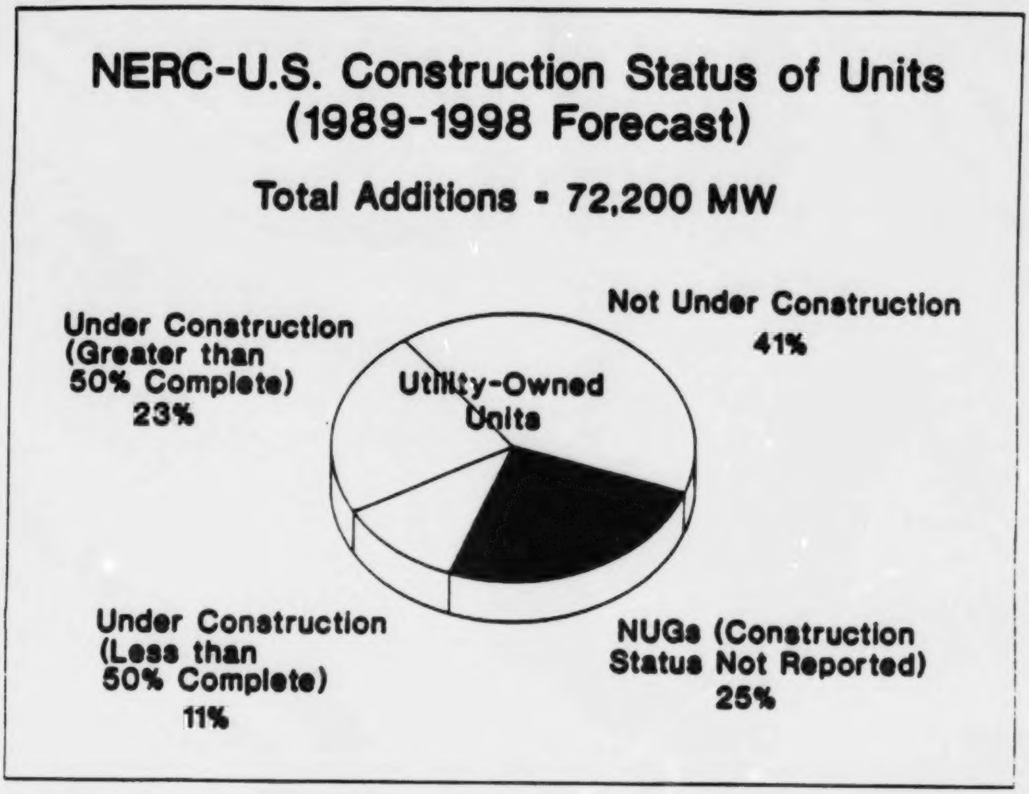

FIGURE 2: Construction status of generation unit additions

Construction is not started on 41% of the planned utility generating unit additions. The nuclear units are all over 50% complete. Two nuclear units (809 MW Shoreham and 1,150 MW Seabrook) are 100% complete but have not been permitted to become operational. Of the coal units planned, 32.9% are not under construction, 34.9% are less than 50% complete, and 32.2% are over 50% complete. Most of the other utility-owned units are not yet under construction. The construction status of the non-utility generators is unavailable.

FIGURE 3

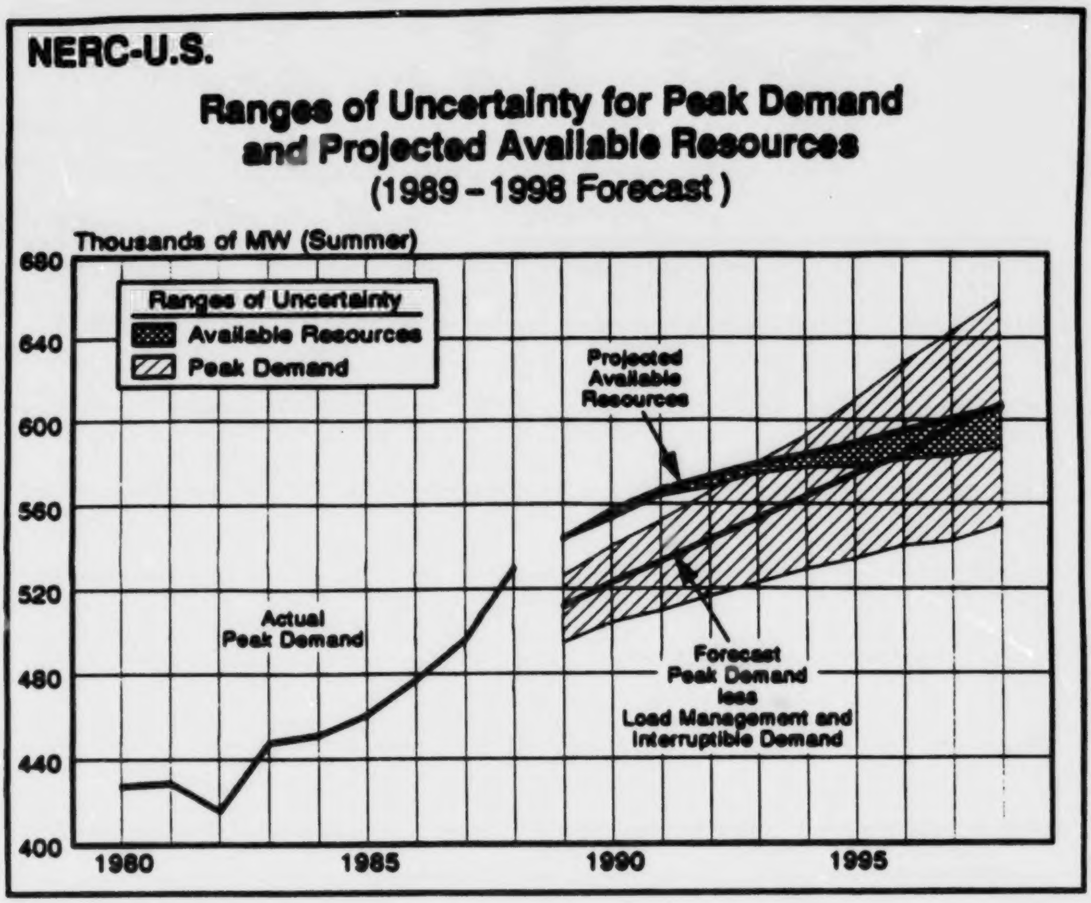

FIGURE 3: Supply/Demand Curve

The projected available resources, the forecast peak demand less load management and interruptible demand, and the actual peak demand since 1980 are illustrated. On a NERC-U.S. basis, the available resources, as planned, are adequate over most of the next decade but are expected to be insufficient by 1998 unless additional capacity commitments are made. Possible delays of new capacity and loss of existing capacity could accelerate the deficiency by two years. If the high bound of the peak demand occurs, there is the possibility of a capacity shortfall by 1993. Not all Regions will experience a capacity shortfall to the same degree or at the same time. Without the use of load management and interruptible demand, a capacity shortfall could occur about one year earlier.

FIGURE 4

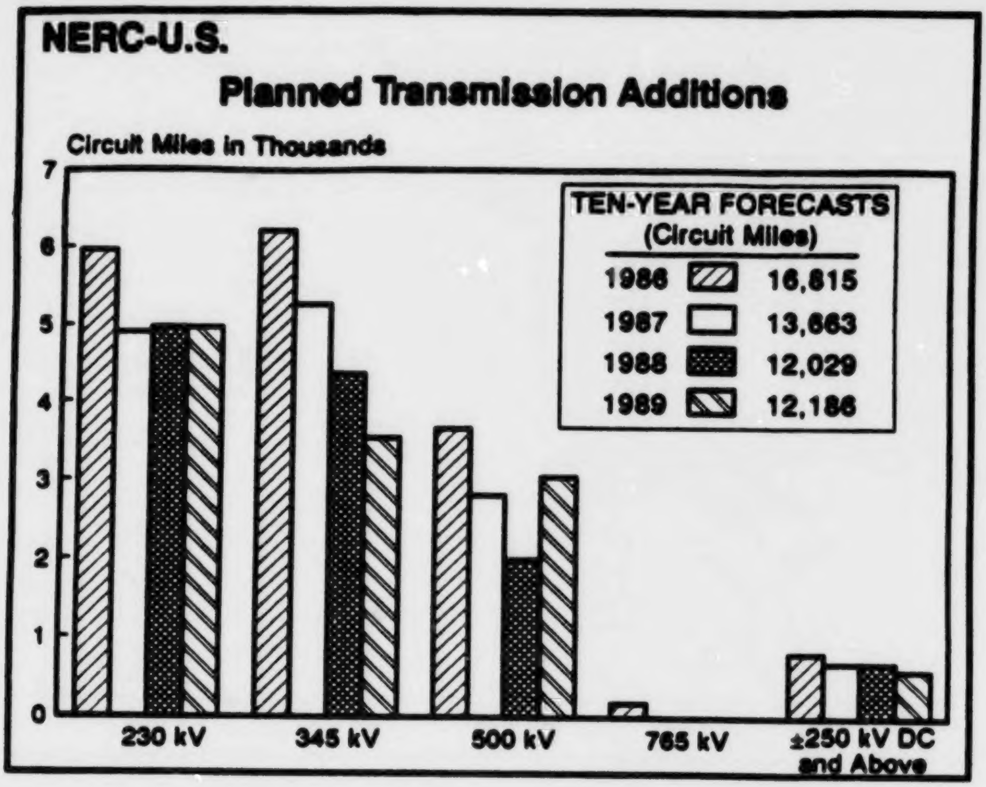

FIGURE 4: Trend in Transmission Additions

New ac and dc transmission facilities planned over the next 10 years total 12,186 circuit miles, up slightly from last year's forecast of 12,029 circuit miles. Bulk electric transmission systems, as currently planned, are generally expected to be adequate during the next 10 years. Reliability deficiencies, however, exist in certain areas of ERCOT, MAAC, MAIN, and SERC. Transmission facilities in these Regions were not allowed to be constructed as planned or the use of the transmission system changed from that which was planned.

Because of the history of disincentives and delays involved with constructing new transmission, there is concern that future transmission capability will not match the need in some areas. The result could be unsatisfactory reliability due to limited simultaneous emergency transfer capability and continuously heavily loaded systems in these areas.

Related Publications

1989 Reliability Assessment (available late September 1989)

1989 Electricity Supply & Demand for 1989-1998 (available October 1989)

Reliability Concepts (September 1985)

Overview of Planning Reliability Criteria (April 1988)

Reliability Considerations for Integrating Non-Utility Generating Facilities with the Bulk Electric Systems (April 1987)

Understanding GADS (October 1987)

Generating Availability Report 1984-1988 (August 1989)

Transfer Capabilities (October 1980)

Impediments to Transfers: An Update (June 1985)

Electricity Transfers and Reliability (available October 1989)

Capacity & Demand – Concepts & Reporting Procedures (January 1987)

1988 System Disturbances (July 1989)

1988 Annual Report (April 1989)

NERC Publications (July 1989)

North American
Electric
Reliability
Council

101 College Road East, Princeton, New Jersey 08540-6601

609-452-8060

THE BASIS FOR UTILITY REGULATION

Presented by

Dr. Adrienne Kwaczek
Senior Economist
Law and Economics Consulting Group, Inc.
Berkeley, California

Energy and Electricity:
Electric Power Planning in 1990s
Montreal, Quebec
June 4-5, 1990

THE BASIS FOR UTILITY REGULATION

Have you ever noticed that the evolution of electric utility regulation has all of the ingredients of a classic fairy tale? As you may remember, all fairy tales begin with "Once Upon A Time" when all lived in peaceful harmony and coexistence and life was good. This is soon followed by a maelstrom of events where one of the main characters becomes a hapless victim of a variety of dangers and perils. As the events carry him at increasing speed toward a terrible fate -- just as things appear to be at their darkest -- a white knight arrives in the nick of time. Thereafter life reverts back to a happy and peaceful coexistence.

Today I would like to relate to you the story of electric utility regulation. There is, however, one slight difficulty -- the end is not yet written. I will have to leave you poised on the brink without a clue as to who, or what, the white knight is. I am sure, however, that over the course of the next few days, you will hear many suggestions and hints as to his identity. You will have to write your own ending but I will try and help you sort through the long list of potential candidates by indicating the questions you may ask in order to determine his sincerity.

Once Upon A Time In America

It its beginning and through its maturing period, the electric utility industry developed into what economists term a "natural monopoly". In essence, the technology was such that costs generally fell as output rose. Given such economies of scale relative to the size of the market, without interference and with sufficient time to reach equilibrium, a single supplier -- a monopoly -- would emerge by pricing all of his rivals out of the market.

From a social point to view, allowing a monopoly in the first place could provide many benefits. The lowest per unit production costs would result since the firm could grow to a sufficient size to exploit the available economies of scale. A sole supplier would also prevent the cost and unnecessary duplication of transmission and distribution facilities.

As with every benefit, there is a cost -- in this case, the potential abuse of market power. Realistically, consumers had few if any substitutes for the product and or alternative suppliers -- leaving them captive customers of the local utility. Such market power would enable the monopolist to extract excess profits from its customers. Relative to the socially optimal result from a perfectly competitive market, a profit maximizing monopolist would produce too little and sell it for too much. Consequently, electric utility regulation was born, instituted to prevent such abuses by controlling the utility's pricing decision. Such oversight was an attempt to produce competitive market place results without actually having a competitive market in place.

Regulators adopted what is, in simple terms, average embedded cost pricing for what were, at the time, quite practical reasons. Marginal costs were then, as now, very difficult to measure precisely but -- more importantly -- in declining cost industries, marginal cost is less than average cost per unit. Hence pricing on a marginal cost basis would have resulted in a total revenue insufficient to cover total cost and some form of subsidy would have been required to keep the utility whole. With no political solution to this problem, average costs had to be adopted.

So from humble acorns do mighty oaks grow. Over time, as the industry has grown and social and political concerns have changed, regulation has matured. It has moved into virtually every facet of the industry from facility siting to financial structures. Despite this pervasiveness, however, the system and structure functioned relatively well, Utilities prospered, demand grew steadily, benefits continued to accrue from economies of scale and productivity increases, rate reviews were infrequent and the real price of electricity fell. A world of peaceful harmony and coexistence.

The Plot Thickens

This is the part where the main characters in the story get caught in a maelstrom of events which moves them ever closer to the brink of disaster. In the tale of electric utility regulation, this is better known as the 1970s and 1980s.

Actually, within the narrower definition of the business of generating electricity, this period was not overly eventful. It does appear that during this time, economies of scale had reached the end, causing productivity increases to slow. These factors, in and of themselves, did not create the problems that followed. Actually, the problems arose not because the electric utility business changed but because the rest of the world changed.

Part of that was the economic environment within which the utilities operated. Interest rates, oil price shocks and inflation increased costs beyond all expectations, especially in fuel and construction, at a time when most utilities were adding capacity to their systems. Further, following in the tradition of any given Murphy's Law, these same forces combined to create world economic recessions, reducing the growth in electricity demand and making the new capacity unnecessary.

The political climate also changed. Regulatory commissions were inundated, highlighting a major flaw that remained undetected for decades -- administrative pricing procedures and policies are a woefully inadequate proxy for market forces in times of rapid change. The price of electricity was reluctantly raised -- too high for consumers and not high enough for utilities. No one was happy -- the regulatory system was perceived to have failed everyone. Perhaps most importantly, ratepayers -- a relatively quiet group of participants to date -- mobilized in the advent of rate shocks and the politicization of regulation began.

Finally, the social arena also changed. Environment became the major issues, followed closely by the potential negative impacts of nuclear power. These issues had a direct impact on the cost of electric plant and generation, further complicating the other economic difficulties facing the industry.

Once Upon A Time in Canada

In order to avoid accusations of one-sided, I should insert a brief discussion of the Canadian version of this tale.

Despite similar childhoods, the Canadian electric utility industry matured into a very different adult that did its cousin to the south. While the U.S. industry is generally dominated in generation by investor-owned utilities, in Canada it is largely dominated by provincial Crown corporations. While there doubt a myriad of reasons why this market structure dominates, two suggest themselves as being particularly important -- economic development and capital outlay. Electricity has long been viewed by some provincial governments as a key resource to promote economic growth and industrial diversification. Further, any of the larger potential power sources were waterways quite distant from the major load centers. Significant amounts of capital were required to build major hydro facilities and transmission systems.

Despite public ownership, many of the Crown corporations are commission regulated to some extent as are all of the investor-owned utilities, although I believe it is fair enough to say that such regulation has not been pursued quite so "vigorously" in Canada as it has in the U.S.

Canadian utilities have not been able to avoid many of the difficulties faced by their American counterparts. The same scenarios and pressures run through both story lines although to some extent, the arena in Canada is somewhat smaller and somewhat quieter. Part of the reason is that impacts obvious in the U.S. industry -- for example, the effect on the financial standing of the utilities -- were internalized in Canada by the government ownership of the industry. While changes in the Canadian industry may lag those in the U.S. by a few years, the "white knights" in both stories are largely the same with slight characterization and motivational discrepancies. It is now time to turn to the final chapter of our story.

The End (?)

The legacy of the 1970s and 1980s is confusion. While the immediate pressure from these events has eased somewhat, the impact of the last 15 or so years has left its indelible mark of the industry and all in it. All major participants -- regulators, utilities, ratepayers, governments -- are questioning that which was traditionally held true. The industry is on the brink of change and the time of the white knight approaches. Where is he coming from and where will he take us?

It is difficult to determine if a particular action or policy will result in what you want until you know what you are looking for. In other words, the talk of deregulation and change is of little help without a clear set of goals of where the industry should be going -- realistic goals based on the industry's current strengths and weaknesses. Once set, all action plans should be judged according to these goals, not according to a particular vested interest or from the point of view of a participant with a particular axe to grind.

I am not so sure that there is a clear set of goals as yet -- at least anything beyond "Anything is Better." The most commonly touted goal is economic efficiency. It must be remembered though that, by definition, efficiency means an efficient allocation of resources through the provision of "correct" levels of supply and reliability at prices which lead to cost-effective utilization decisions both in the long run and in the short run. It does not necessarily mean lower prices nor does it necessarily mean the lowering of barriers -- artificial or otherwise -- to allow certain participants to operate easier. Further, the economic efficiency argument is based on making the industry more competitive as a precursor to the flow of efficiency benefits. In other words, many of the touted benefits rest on the premise that there will be many competitors willing to enter the market so as to provide the benefits from increased competition. It is unclear at this point whether the industry will be lucrative enough to attract sufficient entrants to make the market competitive rather than oligopolistic.

In any event, once a set of goals is chosen, various options can be considered. Partial deregulation can provide valuable insights into the process before it is too far advanced to turn around. Perhaps many of the benefits desired can be achieved without -- and I stress the "without" -- making any fundamental changes to the existing industrial structure. The common thread through most of policy suggestions put forth in the electric debate center around a fundamental premise -- changing the vertically integrated structure of the industry. For example, competitive bidding or two tier regulation of "old and new" generating capacity seek to remove a subset of the decisions regarding generation from the utility umbrella. "Shopping around" and "customer bypass" seek to remove part of the distribution role from utility overview. Finally, mandatory access and wheeling policies are also an attempt to take some transmission decisions out of the grasp of utilities.

There is a compelling reason to consider the debate and arguments from the aspect of industry structure. The electric utility industry has evolved into a vertically integrated geographical monopoly structure for several reasons. Some of these reasons still stand and some do not. We must be careful to find out which remain valid and which have changed as this will have a great impact on the actual realized outcomes of the various suggested policy options. Let us concentrate on how the economic interaction will occur, not on how we would like it to occur.

The primary reason for the structure as it exists today is economies of scale and economies of scope. These economies arise because of coordination and integration within a utility. The responsibility remains under one corporate umbrella and decisions can be made with respect to the whole, rather than just a part. Expansion decisions can be made on a long run basis with generation siting balanced against transmission requirements and the optimality of large units balanced against the need for smaller units serving a different purpose. Putting the choice of generating units and sites in the hands of nonassociated parties reduces the ability to coordinate and balance, reducing the chance that the optimal system will result. Least cost planning and long run forecasts are difficult at the best of times but are even more difficult when some of the crucial decisions and factors become exogenous to the process and impossible to foresee. In a single utility, reserve requirements can be minimized and reliability requirements met at the lowest possible cost considering the system as a whole. Economic dispatch is possible because all units are under the one utility's responsibility and the running of the units can be matched to the demand without regard for nonessential factors. With third party generation, the utility's ability to exercise these options is limited. The efficiency gains that result from this type of coordination and integration are considerable and significant.

There are also significant economies of scope that result from the integration and coordination/cooperation among utilities. Such activities can reduce the amount of reserve required by any one utility, can reduce the need for capital expenditures and can lead to a more efficient use of resources in aggregate. The overall cost savings and efficiency gains from these practices tend to get overlooked in the discussions of the day because they are implicit in the given system. While improvements are no doubt possible, we should make sure that, in our rush to get more, we do not give up too much in terms of what we have.

The success of integration and cooperation depends crucially on the exchange of information and the ability of participants to agree on a common plan of action. Economic dispatch requires knowledge of each unit's marginal cost. Long term planning depends on the capital and operating cost of possible capacity additions. The identification of least cost options requires information on retirements, forecasted demand and load growth and data for load flow studies. Every power supplier must take an active part in the planning and operation of the system if the maximum benefits are to be achieved. This type of cooperation occurs naturally within a vertically integrated corporate structure. Cooperation for the exchange of information is more easily accomplished if there are few participants with a relatively common set of goals and motivations. It may not be forthcoming if participants are competing among one another for resources and customers. A lack of communication can result in incomplete analyses, uncertainty and a less reliable electric system. The ability to reach mutually satisfactory decisions becomes more difficult as the number of participants rises.

The most often expressed answer to some of these concerns is that the difficulties will either be handled efficiently through the market mechanism or will be addressed in long terms contracts. Both solutions I think are overly simplistic. The marketplace will not necessarily handle all of the aspects now internalized by the firm and contracts cannot efficiently replace all of them. The risks and returns will be shifted. It is just not possible to design a contract that will cover all of the contingencies, decisions and tradeoffs that automatically occur within a single corporate structure. To the extent that such decisions cannot be reflected in a contract, there is a real risk that these benefits can be lost. Further, the transaction costs involved with such contracts could easily outweigh the benefits that will ultimately be derived. The resources used in complying with regulation and/or in meeting the requirements of participation in a market are not costless. In the end, we may end up with a system which is really no more efficient but one in which the benefits and costs are simply distributed differently, and not necessarily more equitably.

The response that the market will deal with some of the factors cannot be addressed in contracts is also simplistic in its own way. The market will not necessarily handle all situations efficiently -- if it did there would never have been a market failure argument for regulation in the first place. We really are not sure how the market will develop and react to various events because there is no empirical evidence available.

Not all of these difficulties are insoluble but the severity of the problem and the complexity of the solution likely increases exponentially with the size of the change initiated. Having said this, I do not mean to imply that the industry structure and it regulatory counterpart are perfect as they exist today. There are many things that need improving and many instances in which real gains can be made without sacrificing what currently exists. When we are looking for our white knight, however, I think it is imperative that we figure out just what it is we want to be saved from. With this knowledge we can examine his motivations and solutions from a common perspective rather than just one character's point of view. The driving force behind what is occurring now in the industry appears to be minimization of risk and uncertainty. While this may be an admirable goal, it would be preferable if change came about as a response to a plan of action and ultimate goal rather than as a reaction to a particular event. Otherwise, we run the risk of ad hoc change for the sake of change. The industry must adopt appropriate solutions as opposed to just any solution. As a final point, I would suggest we look at the speed at which our white knight wants to take us to our new Eden. An ounce of prevention is worth a pound of cure.

REGULATORY DEVELOPMENTS AND DIRECTIONS IN CANADA

Speaking Notes For: Philip D. Carter
Director
Electricity Policy Branch
B.C. Ministry of Energy
Mines and Petroleum Resources

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It is a great pleasure to have this opportunity to give you a brief overview of regulatory developments and directions in Canada.

It is generally acknowledged that quasi-judicial types of regulation have significant advantages over more political types of regulation, in the sense that they are generally more focused. Quasi-judicial regulation usually involves the incorporation of expert analytical and technical knowledge, and is more open and has a respectable framework within which to operate.

There are very significant differences in the approaches which Canadian Provinces have taken to regulating their Electric Utilities. In large measure, this is based on differences in the nature and structure of the industries and markets across the country. It also reflects differences in the types of resources which are available to Utilities and also, no doubt, reflects political considerations.

I would like to give you a brief overview of the essential approaches which have been taken by different provinces in Canada towards the regulation of their Utilities. I also want to talk about some important Federal initiatives and recent decisions which have significant implications for the Electric Utility industry in Canada.

The utility companies in Newfoundland are Newfoundland Hydro, which is a crown corporation and a wholesaler of electricity, and Newfoundland Light and Power, an investor-owned retail utility. Both are required to apply to the Public Utilities Commission for approval of rate increases. However, with respect to Newfoundland Light and Power, the investor-owned utility, the Board has the authority to order; with respect to Newfoundland and Labrador Hydro, the Board only has the authority to recommend to Cabinet.

It also is noteworthy that the capital program of Newfoundland Light and Power is not subject to any vigorous review by the Board. The same can be said with respect to the capital program of Newfoundland and Labrador Hydro, which is submitted to Cabinet.

The Utilities in Newfoundland have not implemented any significant demand side management measures, although they are under study. There is no significant co-generation on the island of Newfoundland; there is some self-generation by Industrials, which has been there for quite a long time.

In Prince Edward Island, the Public Utilities Commission has control over Maritime Electric, and somewhat limited control over some municipal utilities. It is notable that the declining block rate structure, which was in place in Prince Edward Island was recently abolished. The province now has peak and off-peak rates. There are annual capital budget hearings held in Prince Edward Island, with public input, and recommendations are made to government.

In Nova Scotia, the Commission of Public Utilities sets prices and monitors environmental concerns and legislation. The Commission's power is essentially in rates; it also has a monitoring role with respect to expenditures to ensure that these are prudent.

The New Brunswick Public Utilities Board began to regulate the New Brunswick Power Commission as of January 1, 1990. Currently, there are not any set guidelines on the decision process for the Commission; however, the Board is in the process of establishing a set of guidelines to follow.

In Quebec, the National Assembly's Committee on Economics and Employment makes recommendations to the Government that affect the operations of Hydro Quebec. The Committee also submits Hydro Quebec's rates to government for approval. This Committee is a subcommittee of the provincial cabinet and is made up of government and opposition members. It is noteworthy, as well, that Hydro Quebec has implemented a very ambitious demand side management program. It is also notable and fair to say that in Quebec, there is a general acceptance of the wisdom of developing projects for the export market. This general acceptance does not exist in other provinces and, from my experience, I can say most notably in British Columbia.

The Ontario Energy Board reviews the proposed rates to be charged by Ontario Hydro to municipal electric utilities. However, there is no authority for the Board to approve, disapprove or fix the bulk power rates which Hydro charges. The Board's role is solely one of review and recommendation. Each April, Ontario Hydro's Board of

Directors submits to the Minister a rate change proposal for the following year. Hydro subsequently supports this proposal by filing an application with the Ontario Energy Board. The Ontario Energy Board report is simply one of many that Ontario Hydro reviews. The Board's report is more of a review of policies and issues affecting costs, revenues, and forecasts; and an examination of trends in expenditures. The review process is much weaker than formal rate regulation. Ontario Hydro also prepares a detailed response to the Ontario Energy Board's recommendations dealing with various aspects of Ontario Hydro's rates, plans, policies, and operations. Ontario Hydro can accept, reject or modify the Board's recommendations for implementation.

The final rate proposal of Ontario Hydro and the Board's recommendation often differ quite widely in any given year. However, the annual review of Ontario Hydro's proposed rates is still a fairly major undertaking. The rate review is much weaker than regulation since the Ontario Energy Board only makes recommendations which do not bind Ontario Hydro. There is, however, evidence that the review has had a moderating effect in electricity price increases in Ontario since 1975.

The annual review is only one form of public review of Ontario Hydro's plans, operations and policies. Since 1975, there have been several major committees and public investigations established to report on and investigate a wide area of Ontario Hydro's affairs and operations. Most recently, Ontario Hydro has engaged in an extensive public consultation program in the development of its demand/supply plan and is about to engage in a review through the Ontario Environmental Assessment Board, to look at the options that are available for Ontario in meeting the future need for electricity.

Ontario Hydro has engaged in thorough, costly and time-consuming public consultation over the five years that it took to develop its demand/supply plan, and the hearing, which is scheduled to start in the fall of this year, on that plan; is intended essentially to improve the level of public understanding of the various options which Ontario Hydro has, and also to give the public a better appreciation of the trade-offs that are inevitably part of choosing one option over another.

Ontario Hydro has clearly signaled that it intends to make public consultation an important part of the electricity supply planning process in Ontario. I feel that Ontario Hydro, in the hearing on the demand/supply plan, and the associated environmental study, is hoping that this process will prove the need issue in advance of site specific hearings. That is to say that Ontario Hydro aspires to having this process lead to a greater consensus in Ontario on what the most attractive options are on the demand and supply side for meeting Ontario's electrical energy future.

It is also worthy to note that in Ontario there have been recent changes to the Power Corporation Act, together with a new Memorandum of Understanding between the Government and Ontario Hydro, to set up a new system of reporting between Hydro and the Government, which requires the Utility to conduct its planning in accordance with government policies.

Prior to early 1989, the Manitoba Utilities Board only made recommendations to the Government of Manitoba following rate reviews. After 1989, Acts were changed giving the Public Utilities Board the authority to set rates instead of just recommending an acceptable rate. The Public Utilities Board in Manitoba does not have the power to direct Manitoba Hydro as to what projects to build; it can only make recommendations. However, the Board does have the authority to examine all monetary issues which will affect the setting of rates. As a consequence, if it is found in hindsight that alternative supply options would have been better in the Public Utilities Board's judgement, rates can potentially be set according to the costs associated with the lower cost option, instead of the actual costs of the option that was selected by Manitoba Hydro. This process is essentially intended to keep the Utility on its toes, and it usually heeds the Board's recommendations when deciding on which projects to build. The Public Utilities Board of Manitoba has also been asked to review Hydro's 20-year capital program, and make recommendations to government.

Until 1987, Saskatchewan had a Public Utilities Review Board which regulated prices. With Cabinet approval, prices are now essentially up to the utility in Saskatchewan, with Saskatchewan Power deciding on appropriate rate levels based on the cost of production. Large energy projects in Saskatchewan, do require an Environmental Impact Assessment, but at the discretion of the Minister. All SaskPower projects must conform to the rules stated in the Environmental Assessment Act.

In Alberta there are two regulatory boards--the Public Utilities Board and the Energy Resources Conservation Board. The Public Utilities Board only has regulatory power in the area of ratebase, rates, financing, and contracts. The Public Utilities Board in Alberta is only responsible for regulating the wholesale rates of electricity based on cost of service.

In order to realize more equal prices from one region to another within the province, Alberta established the Electricity Energy Marketing Act, whereby the Public Utilities Board buys all generated power in the province at the set rates. The pooled power is then sold back to all three utilities at a pooled price.

In Alberta, energy projects of a certain size must obtain a construction permit from the Energy Resources Conservation Board, which assigns Utilities service areas and approves new facilities. It is also noteworthy that Alberta, following an inquiry into all aspects of small power generation, passed the Small Power Research and Development Act in mid 1988. This legislation gives special status to the IPPs to ensure generation from renewable resources and biomass, and provides for a total allocation over the period to the end of 1994 of 125 megawatts of capacity to eligible small power projects.

Finally, British Columbia. I will confine my remarks to B.C. Hydro, the major utility in British Columbia, which came under regulation in 1980.

In addition to other relevant legislation, B.C. Hydro and the B.C. Utilities Commission operate under two special directions from the provincial government which, I believe, are unique in Canada.

Special Direction number two provides for a premium payment to IPP projects which will reduce environment pollution in communities where they are developed. Special Direction number three, to the B.C. Utilities Commission is designed to ensure that B.C. Hydro meets minimum financial standards and avoids future rate shocks by raising rates in a smooth, predictable and stable manner. Special Direction number three further directs that rates should contribute to conservation and efficient electricity use, by recognizing that rates should gradually increase to meet the higher costs of new electricity supply and to generate a return on public investment.

Through these special directions, the Cabinet of the Government of British Columbia can direct the B.C. Utilities Commission with respect to regulation and rate making, not withstanding any other provisions of the Utility Commissions Act. These special directions are an open expression of Government policy, and give that policy profile and visibility in British Columbia.

B.C. Hydro recently filed a rate application, and the B.C. Utilities Commission made a ruling at the end of April. The rate application was characterized as proposing policy-based rates. The proposed rate increases were not based on costs, and it was indicated through the course of the hearing that the rate increases which were sought were not necessary to meet the financial standards of the corporation. It was indicated by B.C. Hydro that the rate increases were sought to give consumers a price signal that would give them an incentive to undertake conservation and efficiency.

Rates in British Columbia have been declining in real terms for four or five years, and it was felt that as a result of real declines in prices consumers were much less concerned about ensuring efficient use and conservation of electricity. So the rate application was designed to give the signal that consumers should conserve, by using a price incentive.

During the course of the hearing there were many interested parties, among whom was a gentleman called William Beaumont. Mr. Beaumont made a written submission which was directed to the Commission's Secretary. The letter contained the following excerpt:

> "I had a dream last night that a man came to visit me. He was fairly well dressed, and it was quite a hike up to our place, so I invited him to stay awhile. We sat on a step in the garden. it seems he wanted to talk about real estate. Two of the neighbour's rather large dogs were running around and got behind us and were licking our ears. And I took a swat at one of them over my shoulder, and I awoke just then to the sound of my wife's groans. Guess who had just been struck a blow on the head?

> I was reminded also of the woman who instructed the teacher that her child was not to be disciplined. If he misbehaved and she became angry with him, she should slap the child next to him and that would serve to remind him to behave himself.
>
> So B.C. Hydro is telling the Public Utilities Commission that the public needs to have its face slapped for wasting electricity. Like Mother Hubbard goes to her cupboard to get some more electricity and finds that her cupboard is bare, so she slaps her children for being wasteful and sends them to bed.
>
> In actual fact, all the waste is at the other end. It is the executive officers of Hydro who should have their collective faces slapped."

The Utilities Commission in its decision certainly did not go as far as Mr. Beaumont in terms of dealing with the rate application, but the Commission's decision was essentially to disallow that part of the rate increase which was associated with what Hydro felt was a need to give individuals a price signal to conserve. The Commission took the view that the evidence presented at the hearing was not persuasive with respect to the relationship between the general level of prices and the general level of consumption. The Commission's view was that conservation and efficiency should be dealt with through rate design.

Is is also noteworthy that the B.C. Utilities Commission also decided in the rate decision that B.C. Hydro would have to file tariffs, budgets, and other information so the Utilities Commission would effectively be able to regulate B.C. Hydro's PowerSmart Programs. (PowerSmart Programs are demand side management programs.)

Hydro argued during the rate hearing that PowerSmart should not be regulated by the Utilities Commission, and that Hydro required flexibility to be able to test these various programs in the market and adjust them according to their experience.

In its Decision, the Utilities Commission found that demand side management was the preferred resource alternative of B.C. Hydro, and it should be dealt with in the same manner as any other major resource option, including a supply option such as the Site C hydro electric development.

Finally, the federal Government. In September 1988 the Federal Minister of Energy, Mines and Resources announced a new Federal Electricity Export Policy. This policy proposed streamlining the regulation of electricity exports, and international and interprovincial power lines by accepting provincial decisions on these matters, which adequately dealt with extra provincial impacts and complied with relevant federal environmental standards, and which provided other domestic utilities with fair market access.

The National Energy Board has indicated that it will conduct public hearings only if compelling evidence is presented.

The normal procedure would be to issue an export permit automatically following provincial approval. Full implementation of the new policy will require amendments to the Act and other regulatory amendments, which are expected soon. To allow the Board to evaluate any public concerns over the environment, the Board decided that it is necessary to ensure full notification to the public of proposed applications having potential environmental and social effects. As a result, the NEB issued a memorandum of guidance pertaining to the need for NEB applicants to implement a public consultation notice.

The intent of the memorandum of guidance is to provide for public input during the project planning and development stage, which may then be incorporated into applications to the Board. The Board has not outlined any specific requirement for public consultation, in order to give the applicant as much flexibility as possible.

Recently, there have been two landmark cases dealing with the Federal Environmental Assessment Review Guidance Order in the area of resource development. These are, of course, the Rafferty and Alameta dams in Saskatchewan, and the proposed dam at the Three River site on the Oldman River, to ensure a secure supply of water within the South Saskatchewan River Basin in Southern Alberta.

Both of these developments are on rivers which cross interprovincial boundaries. The Souris river also flows over the Canada U.S. boundary.

In the case of the Rafferty and Alameta dams, a license was granted by the Federal Minister of Environment; however, it was found that the environmental assessment prepared in Saskatchewan did not contain an assessment and review of the environmental impact of the project in North Dakota nor in Manitoba and did not, therefore, comply with the provisions in the federal guidelines order.

In March 1990, the Federal Court of Appeal reversed a lower court decision and granted orders which cancelled the approval for the construction of the Oldman River Dam previously granted by the Federal Minister of Transport. The Court of Appeal held that invoking the federal EARP process was not a duplication of provincial effort since Alberta's project evaluation process did not allow for a full opportunity for public participation and evaluation by an independent review panels.

The EARP guidelines of the Federal Government must now be considered as having legal force rather than being merely a policy statement or guideline. In the recently released Green Paper, the Federal Government indicated that it intends to table legislation to strengthen application of EARP. This plan also states that the Federal Government will not approve without a vigorous environmental assessment, initiatives that could have an impact on the environment.

It is difficult to imagine a project of any significance which would not require the application of the EARP Guideline Order and, therefore, would come under federal review.

While federal environmental rules are somewhat uncertain--especially with respect to justification or need for a project and whether this will be encompassed in federal reviews-- it is clear that for major projects the provinces alone cannot make the decision to proceed to construction until the federal process is satisfied, and the federal government is essentially on side.

So, in conclusion, there are very different structures and very different approaches to regulation by provinces in Canada. The approaches adopted reflect the uniqueness of the systems, markets, and industries in the provinces and, no doubt, political and public policy considerations. It is also noteworthy that there are differences in professional staffing resources and in the funding of interveners in provinces where quasi-judicial regulatory processes are in place; this realistically impacts on the effectiveness of the regulatory process.

There is clearly a move towards a more formalized review of utilities decisions and options. With increasing emphasis on conservation, efficiency and the environment, Boards and political bodies will increasingly want to be convinced that Utilities have fully evaluated and pursued all (economic and environment) least cost options, on the demand side and the supply side.

There is an increasing emphasis on discretionary programs, and there is also a movement toward modification of rates, to pursue conservation and efficiency objectives.

There is also a move, I suggest, toward environmental premiums for demand side management and other options which have a net environmental benefit.

Finally, public consultation will increasingly become an important part of the electricity supply planning process, and will be necessary to satisfy regulatory requirements. I would emphasize that this should not be viewed as just going through the motions. Utilities will increasingly have to incorporate public consultation into the electricity supply planning process. This may also include taking account of the willingness of consumers to pay for conservation and efficiency, as may be revealed through public consultation.

Regulatory Developments and Directions in the United States[1]

by

Dr. Charles G. Stalon
Director, Putnam, Hayes & Bartlett, Inc.
Washington, D.C.

Energy and Electricity: A Conference on
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INTRODUCTION

In a world in which scientists have invented a method of invention, large corporations have routinized innovation and competitive market opportunities continually subvert the economic and political status quo, an efficient economy cannot be seen as one in which a particular "bill of goods" is efficiently produced. Instead, it must be seen as one that adjusts continually, efficiently producing different "bills of goods" as technological and trading opportunities change. This principle must become the dominant guiding principle for electric utilities and for their economic regulators.

As part of the process wherein a society adjusts to never-ending technological knowledge and opportunities, the responsibilities of economic regulatory agencies such as state public utility commissions (PUCs) and the Federal Energy Regulatory Commission (FERC or Commission) are redefined. These agencies are required to adjust not only to technological opportunities as they see them, but also to public values, sometimes expressed in law and sometimes in the decisions of other economic decision units. Furthermore, public values extend beyond desires for goods and services. They include preferences for certain techniques of production, for certain agency decisionmaking processes and for certain industry structures. One recent manifestation of change in U.S. regulation and in the U.S. electric industry was the publication by the FERC in October 1989 of a report submitted to the Commission by a Transmission Task Force (TTF) appointed approximately a year earlier by Chairman

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[1] Parts of this paper are taken from the author's paper entitled "The Significance of the FERC's Transmission Task Force Report in the Evolution of the Electricity Industry," to be published by Columbia University School of Law, Center for Law and Economic Studies.

Martha Hesse.[2] The publication of the TTF Report can be interpreted as an attempt by the FERC to understand and guide impending changes, or at least to focus the debate on options for change.[3]

I find it useful to emphasize the FERC's Transmission Task Force Report as a response to (1) the technological opportunities affecting the industry, (2) the developing stresses in the federal/state bifurcated regulatory model and (3) the increasing public respect for competition as a disciplining force rather than economic regulation. In particular, the inability of economic regulatory agencies to make timely decisions under existing decision procedures requires a rethinking of the responsibilities that can be assigned to such agencies.

The Task Force Report was not simply a passive reflector of external forces. The TTF Report reflects the best tradition of economic regulatory agencies. It recognized certain deficiencies in one of the industries regulated by the FERC. It recognized recent changes in political realities, some manifested in law and others manifested in regulatory decisions. It recognized that some alternatives for improving the economic performance of the industry were severely constrained by inherited regulatory structures and traditions. In light of these recognitions, it defined certain options for improving the economic performance of the industry and evaluated some of them. In so doing, the TTF Report contributed constructively to a necessary and important debate by providing that debate with structure and focus.

The TTF Report addresses many topics and must be permitted to speak for itself on most of the topics addressed. Today I want to address one criticism of the Report. That criticism is that the Report suggested greater reliance on competition in an industry when what is needed is a return to past practices -- that is, to less competition. Critics contend that the Report should have called for a reaffirmation of monopoly structure in the electric industry and a restoration of the old regulatory compact. This topic, I believe, encapsulates one of the crucial issues in the current debate over the future structure of the U.S. electric industry. Time constraints require that I address only a small part of the topic.

Expository convenience dictates that I confine my remarks to two subtopics: (1) the need to avoid confusing what *can* be done by a monopolist and what *will* be done by a monopolist, and (2) the need for a new risk allocation model in the electric industry. I will discuss the first briefly and the second more extensively.

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[2] *Electricity Transmission: Realities, Theory and Policy Alternatives*, the Transmission Task Force's Report to the Commission, Federal Energy Regulatory Commission (October 1989).

[3] It is useful to recognize that the only two Commissioners who endorsed the Report have left the Commission.

"CAN" VERSUS "WILL" IN MONOPOLY ANALYSIS

Economic analysis of decision units can sometimes be conveniently divided into two questions:

1. What can an economic decisionmaker do in a relevant circumstance? Such an analysis normally explores technological possibilities and the financial, political and social constraints of the decision unit.

2. Of all the things the economic decisionmaker can do, which one will it choose to do?

An answer to the first question requires a knowledge of facts. An answer to the second question requires a knowledge of the objectives of the decision unit.

Competitive markets tend to give firms that want to survive few choices. Consequently, if survival is an objective of a competitive firm, it may not be necessary for the analyst to emphasize the differences between what the firm can do and what it will do. In contrast, a monopoly firm often has many decision strategies consistent with its survival. The strategy it chooses, therefore, will be dictated by an objective other than survival. Consequently, social policy cannot be based on an argument that a monopolist *can* serve a defined public interest without regard to what the monopolist *will* do if allowed to exist.

One observation serves to illustrate this conclusion. It is a likely truth that whatever a competitive industry can do, a monopoly can also do, since it can arrange its structure to be competitive if it so chooses. In addition, a monopoly can do many things a competitive industry cannot do. Such a truth has not led many economic observers to argue for the replacement of competitive industries with monopolies.[4] The reason for the social bias in favor of competition is obvious. The incentives for profit-seeking monopolies is not to produce economically efficient outcomes, but, rather, to seek high profit, or profit-maximizing, outcomes that are not economically efficient.

The conclusion I draw from this analysis is obvious. Any argument that asserts that the nation should reaffirm vertically-integrated monopolies as the preferred structure for electric utilities on the grounds that monopolies *can* be more efficient than an industry structure with competitive generators must be dismissed as irrelevant until it is strengthened by showing what vertically-integrated monopolies *will* do. Furthermore, since a monopoly structure requires economic regulation and a competitive structure does not, a social choice between structures must depend to some extent on the perceived efficacy of economic regulation.

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[4] In the United States, the one major exception to this generalization was the passage of the National Industrial Recovery Act of 1933, which created the National Recovery Administration. The Supreme Court voided the Act in 1935, apparently to the relief of almost all.

RISK ALLOCATION IN THE MODERN ELECTRIC INDUSTRY

With these long, prefatory remarks in mind, it is now time to turn to my principal point; namely, that the risk allocation model developed in the electricity industry in the 1950s and 1960s does not appear to be suitable for the industry in the 1990s. Furthermore, the development of a new model probably requires an important role for independent power producers (IPPs) as a necessary condition. That condition, as necessary as it is, is probably not sufficient. However, such a change requires a reconsideration of terms for access to the network.

The Demise of the Industry-Preferred Risk Allocation Model

The last 20 years have been years of turmoil in the American economy. It is not surprising, therefore, that the last 15 years have been tumultuous ones for electric utilities. One of the most important questions this turmoil has posed is: Who will bear risk in this industry? The electric industry is confronting the need for major capital outlays in the next decade. For reasons associated with risk, many regulated utilities seem committed to buying power from IPPs and PURPA qualifying facilities (QFs) rather than building their own facilities to produce that power. Since that possibility motivated some of the important conclusions of the FERC's TTF Report, it is worthwhile to review the recent evolution of the risk allocation model.

A common assertion is that the regulatory compact between economic regulators and regulated firms was "broken," or at least "amended," in the 1970s and 1980s. Whether broken or amended, the argument, when presented by regulated firms and their financiers, seems always to conclude that it was the state that unilaterally altered the compact. It is usually argued that the regulated firms lived up to their end of the bargain. A counterview deserves exposition.

It is noteworthy (and a point whose importance the FERC's Task Force recognized) that the charge is not always that PUCs broke the compact. Sometimes (and experience varies from state to state), it is granted that the PUC did its best to honor the compact: It was the legislature, or the governor, or the attorney general or some combination of these, that directly broke the compact or coerced the PUC to break the compact. In some cases, it is asserted, it was clear that when the PUC upheld the utility view of the compact, the appointing official appointed different members to the PUC, or, when members were elected, the populace elected new members. In other cases, it is argued, the legislature explicitly changed the law and mandated new standards for risk-bearing. "The Electric Utilities Executive Forum" reported in the May 25, 1989 issue of *Public Utilities Fortnightly*[5] several assertions by utility executives attributing the unfavorable change in regulatory rules to changes in laws. From my personal experience I could list several more. In any case, there is widespread recognition that utilities and regulators were, and still are, being pressured to place more of the risk of constructing assets on utility stockholders and less on utility ratepayers.

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[5] Vol. 123, no. 11, pp. 72-106.

Summary of the Principal Thesis

The regulatory compact that exists today, and likely will exist in the near future, is not the one that regulated firms and their financiers thought existed before the 1970s. Either that compact never existed except in the minds of managers and financiers, or, if it actually existed in the minds of regulators and legislators also, it has been amended. The terms of the regulatory compact cannot be evaluated separately from the macroeconomic conditions in which the compact is being exercised. Furthermore, macroeconomic conditions are not likely to return to those that existed during the "Golden Age" of regulation -- a Golden Age as seen from the perspective of utility managers and financiers. Consequently, there is no Golden Age for capital-intensive utilities in the foreseeable future.

The conclusion I draw from these observations, and the conclusion I want to support, is the following: If investors are to avoid unnecessary losses, and the nation is to avoid unnecessary inefficiencies in regulated industries, certain terms in the regulatory compact as it now exists must be recognized and honored. Efforts to recreate the compact that existed in the minds of utility managers and their financiers before 1970 is likely to be an invitation to further inefficiencies.

The Thesis Developed in Detail

Risk-Bearing before the Early 1970s

The dominant theme in risk-bearing before the 1970s in both the natural gas and electric industries was that almost all risks were to be shifted to end-users. Rather than concentrate risks on professional risk-bearers (primarily equity investors) who stand ready in a market society to bear risk in exchange for a reward, utility managers and their financiers supported franchise terms, tariff terms, rate designs and equity ratios that shifted risks to end-users. Regulators, who often lacked financial sophistication and who often thought in terms of nominal prices rather than efficient real prices, quietly acquiesced or, more often, endorsed such actions because the immediate consequences were attractive, i.e., nominal prices were reduced.

In the natural gas industry, the Federal Power Commission (FPC), predecessor of the FERC, created a system of natural gas regulation that illustrates this point. Building long-distance, long-lasting pipelines raised two risks: the risk that gas supplies would not be sufficient to fill pipelines for periods long enough to recover their construction costs, and the risk for individual pipelines that end-use markets would be lost before construction costs were recovered. In order to accommodate the risk-averse demands of LDCs, pipelines and financial markets, the FPC adopted a three-part strategy:

- Pipelines were permitted to offer a bundled service, i.e., they were not required to offer transportation separately. Most of the long-distance pipelines offered only a bundled service.

- On the supply side, the FPC imposed requirements such that each pipeline was required to demonstrate that it had large reserves of gas under contract before a certificate was issued to permit construction or to serve new markets from existing assets. These contracts were usually for 20-year terms. Such long-term contracts assured LDCs served by the pipeline that supplies were adequate to justify the local expense of shifting from coal gas to natural gas. The contracts also assured end-users that investments made in gas-using equipment could be amortized over long periods.

- On the demand side, the FPC strategy ensured pipelines a market for their gas reserves by limiting the access of competing pipelines to certificated end-use markets. To further strengthen each pipeline's monopoly power, the FPC also approved tariffs for sales to LDCs containing long-term contract demands, minimum bills and, in some cases, sole supplier requirements. Long-term contract demands effectively shifted most of the risk of building assets to LDCs. Minimum bills effectively required LDCs to pay for some volumes of gas not taken. A sole supplier tariff is a tariff in which an LDC receives a preferred rate in exchange for its promise that the LDC will not purchase gas from any other source.

As a consequence of this three-part regulatory strategy, the risks of the pipeline industry, including the risk of the ever-changing value of reserves, were effectively shifted downstream to end-users. The combination of strong monopoly power with market entry largely blocked, minimum bills and sole supplier tariff provisions virtually guaranteed pipelines comfortable earnings on their assets.

One essential ingredient in this regulatory strategy was what later came to be called the *Narragansett* doctrine.[6] Another element was also essential; namely, constricting the scope of what later came to be labeled the *Pike County* exception to the *Narragansett* doctrine.[7] The crucial holding in *Narragansett* was that a PUC could not question the reasonableness of rates set by a federal regulatory agency. Consequently, LDCs were assured that costs incurred for pipeline company services could be recovered from LDC customers. Federal regulation, therefore, not only assured pipelines of the ability to shift the risks of long-term contracts between pipelines and producers to LDCs, it also assured LDCs that those risks could be shifted to the LDC's customers. The *Pike County* doctrine asserts that a PUC can challenge the prudence of an LDC's purchasing decision when the LDC has a choice among federally-approved rates, or a choice between federally-approved rates and intrastate free market rates. However, sole supplier tariff provisions, minimum bills and certification barriers served to constrict LDC choices, and thereby "protected" them from gas-purchasing prudence challenges of PUCs.

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[6] *Narragansett Elec. Co. v. Burke*, 119 RI 559, 381 A. 2d(1977) cert. denied, 435 U.S. 972 (1978).

[7] *Pike County Light & Power Co. v. Penn. Util. Comm'n.*, 77 Pa. Comm'w. 268, 476 A. 2d 735 (1983).

In the electric industry, where capital intensity of output was greater, the principal risk allocation decisions were those that preserved monopoly power by denying customers a choice of suppliers. A second key decision was that which dictated a capital recovery schedule (usually a straight-line depreciation schedule) that was to be honored by the regulatory agency without regard to demand conditions. With capital recovery schedules assured, equity ratios could be kept small since most risks were to fall not on equity holders but on end-users. The other side of this risk allocation coin became obvious in the 1970s and 1980s when demand rose less than projected. The risk-bearing model required that rates rise. In short, the risk allocation model imposed by a coalition of utility managers, utility financiers and acquiescing regulators called for demand-perverse pricing -- that is, prices must rise when capacity is abundant and must fall when capacity is in short supply. Such was the social cost of imposing a risk allocation model that drafted the nonprofessional end-user as principal risk-bearer for the industry.

Risk-Bearing during the 1970s and Early 1980s

During the late 1970s and early 1980s, regulatory ratemaking was marked by a political rebellion. In the early 1970s, regulators exploited the decision process of PUCs to resist price increases. In so doing, they allowed, or coerced, rates of return to fall toward, or to, those explicitly endorsed in formal proceedings. Later in the 1970s, after the final OPEC shock and the resulting high nominal interest rates and high inflation rates, ratepayers, joined by politicians, used formal ratemaking proceedings to allow, or coerce, rates of return below those explicitly deemed appropriate by PUCs. The rallying cry for opponents of rate increases was that ratepayers should not pay for managers' forecasting mistakes. The risk allocation model created in previous decades was being rejected in a crucial political test. The model failed the first test of a good model: it failed when it was needed. The fact that it worked when it was not needed, i.e., during the 1950s and 1960s, was not much consolation to utility investors in the late 1970s and early 1980s.

Risk-Bearing in the Late 1980s

Current debates demonstrate that risk allocation in the electric industry is a problem currently without a sustainable solution. Regulators and regulatees are experimenting with alternative risk allocation models, but without much of a constructive debate. In the natural gas industry, the FERC, in Order No. 436, attempted to extricate itself from the role imposed on it by the FPC-created bundled-service system of regulation -- that is, the role of explicitly shifting risks of holding gas inventories to natural gas end-users. The FERC did this by encouraging pipelines to provide nondiscriminatory access to transportation services. By removing pipeline companies as monopoly merchants of gas -- that is, by allowing LDCs or end-users to negotiate directly with natural gas producers -- the allocation of risk for holding an inventory of gas could be directly negotiated.

This regulatory strategy was encouraged by many developments in the industry, but the one event above all others that illustrated the need for a change was the failure of the old risk allocation model. In the early 1980s, it became obvious to all industry observers that the bill for forecasting failures that the then-existing risk allocation model required regulators to present to end-users in order to keep producers, pipelines and LDCs "whole" was truly staggering. Contracts between producers and pipelines had imposed risks on end-users far beyond anyone's projections. Not merely was the bill so large that it was bound to create a regulatory and political reaction, it probably exceeded the wealth that existing monopoly power could extract from end-users, even if regulators had allowed the full exercise of those powers.

This is not the place to debate the wisdom of policies actually adopted and those allowed to evolve to allocate actual losses; nor is it the place to discuss the role of long-term contract demands in allocating asset risks efficiently in the pipeline industry. Here, the only conclusion needed is that the old risk allocation model proved unsustainable. The slowness of recovery of the long-term contract market for natural gas is evidence of the struggle to create an alternative risk model.

In the electric industry, the search for a sustainable risk allocation model has manifested itself primarily in negotiations between electric utilities and IPPs. This is an intense debate with no generally accepted model having yet emerged.

Interim Conclusion

During the late 1970s and 1980s, states, acting through PUCs and/or legislatures in response to protests from ratepayers and sometimes in recognition of the limits of monopoly power and/or in recognition of gross inefficiency, made it very clear that the system of risk allocation developed by and for regulated firms before the 1970s was not sustainable when the bill to end-users was large. The lesson for regulated firms and their financiers seems clear. They must now do one of two things:

- They must develop and encourage regulators to endorse a more sustainable model of risk allocation, or

- They must place their bets on the proposition that events of the late 1970s and early 1980s were unique and that lessons drawn from that period are not particularly relevant for the future of regulated firms.

THE GOLDEN AGE OF REGULATION WILL NOT LIKELY RETURN

A corollary to proposition number two is that the pre-1970s condition is the "norm," and that the probability that non-normal circumstances such as the 1970s and 1980s will recur in the relevant future is so close to zero that reasonable investors can wisely act as if it is zero. This point I will return to later, but first I want to elaborate on this conclusion.

Long-term contracts between IPPs and electric utilities are remarkably similar to long-term contracts between natural gas pipelines and producers. Electric utilities that expect to pass the cost of such contracts to end-users of electricity without regard to demand conditions should look closely at the contract problem that has plagued the gas industry since the early 1980s. The lesson I would draw from this and other experiences of the 1970s and 1980s is that electric utilities should use contracts with IPPs to improve the efficiency of their pricing. They should seek to create contracts that will allow them to escape the demand-perverse model of pricing. This almost certainly means that IPPs must bear much of the risk of an uncertain capital recovery pattern. It does not mean, however, that they must accept an uncertain present discounted value of the generating asset. Regulatory traditions, e.g., Allowances for Funds Used During Construction and accelerated depreciation, are building blocks with which firms can work to gain efficient prices and tolerable allocation of risks. When negotiating contracts, the objective must be efficient prices, not low nominal prices with hidden risks imposed on end-users.

Conditions for a Virtuous Cycle

The sustainability of the terms of the regulatory compact cannot be evaluated separately from the macroeconomic conditions in which the compact is expected to govern. In order to expand on the meaning and significance of this point, it is useful to examine the essential ingredients of the Golden Age of Regulation -- that is, the period from about 1947 to about 1970. Essential ingredients of the Golden Age were (1) long regulatory lags and (2) a rate of productivity increase larger than the rate of inflation. Long regulatory lags meant that regulators were slow to respond to the signals calling for price changes. Above-normal rates of return could, consequently, persist for quite some time before regulators coerced price reductions. Fully aware of the clumsiness of their formal proceedings, many regulators chose not to initiate price reduction proceedings but to invite utilities to voluntarily reduce prices and avoid formal proceedings.

The circumstance of productivity increase rates larger than inflation rates means that nominal unit costs will fall. Consequently, the rate of return tends to rise between price reductions. These circumstantial ingredients combined with the institutional passivity of PUCs to create a virtuous cycle that defined the Golden Age. The virtuous cycle can be seen as a four-phase one:

- *Phase One*. The productivity increase rate greater than the inflation rate lowers unit cost and increases the rate of return.

- *Phase Two*. The PUC, responding with a substantial delay to the above-target rate of return, negotiates a rate of return reduction that "shares the benefits of technological improvements" with ratepayers. Such sharing allows the utility to keep some returns above the target and allows the utility to have a major voice in selecting the prices to be reduced.[8]

- *Phase Three*. The utility, by focusing price reductions on the price-elastic segments of its market, emphasizes growth and new capacity where the productivity rates are the highest.

- *Phase Four*. Increasing the proportion of high productivity assets in the asset mix complements other productivity increases to maintain productivity well above the inflation rate, thereby further lowering unit costs.

It is worth stressing that in the virtuous cycle, growth in quantity demanded was seen by the utility, the regulators and the ratepayers as something good. Since new plants had significantly higher productivity than old plants, the introduction of a new plant lowered both real and nominal unit costs. The virtuous cycle depended on this phenomenon.

Conditions for a Vicious Cycle

Conditions for a virtuous cycle no longer exist. Consequently, conditions for a Golden Age no longer exist. In fact, current and foreseeable circumstances almost certainly mean that the vicious cycle operating in the last decade will continue, perhaps with diminished intensity. The essential ingredients for a vicious cycle are (1) a long regulatory lag and (2) a productivity increase rate significantly lower than the inflation rate. The latter ensures that nominal unit cost rises between formal price determinations and the former ensures that rates of return will tend to be below the target rate.

In a vicious cycle, rising unit nominal cost (real unit costs may be rising or falling) requires utilities to continually petition PUCs for price increases. Ratepayer opposition to those increases means that PUCs respond with a lag and compromise target rates of return so that utilities seldom get what they believe necessary. Furthermore, the PUC takes the initiative on rate design, using rates for whatever economic growth or social objective is deemed appropriate.

With the rate of productivity increase significantly smaller than the rate of inflation, new plants (no matter how much they lower real unit costs) raise nominal unit costs and, therefore, nominal prices. Consequently, growth in quantity demanded is seen as something to be minimized, or possibly avoided. Therefore, rate design and demand-side management become tools to be used for such purposes.

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[8] The procedure for leaving the utility with an above-target rate of return was often as simple as using a historical period to determine unit costs.

CONCLUSION

The Golden Age of the 1950s and 1960s will return only if the rate of inflation falls substantially, and/or the rate of productivity increase rises substantially, and/or the regulatory leopard changes its spots. Since I do not see any of the three happening and especially cannot see the rate of inflation falling below the rate of productivity increase, I must conclude that the Golden Age will not return soon. I deduce from this conclusion the further conclusion that the 1950s and 1960s are not the "norm" to which investors should look for lessons. It is more likely that the norm for appropriate lessons for the 1990s is the 1970s and 1980s.

The regulatory compact was modified into a socially unacceptable form during the Golden Age and before by the natural, and not properly restrained, inclinations of managers, investors and financiers who always want a "sure thing"; that is, investments with no detectable downside potential and great upside potential. In pursuit of that objective, they induced regulators to acquiesce, temporarily, to a risk allocation model that became unsustainable when the price tag to end-users was revealed.

Risk analysis and the evaluation of risk allocation models must start with the recognition that some risks are inevitable. He who creates an asset that is capable of rendering services over a long period of time gives hostage to fortune. The job of the regulator is to encourage an allocation of risk among investors and ratepayers that facilitates the development of efficient investment patterns and efficient prices. One useful principle for regulators to keep in mind is that this objective is not identical to the objective of minimizing nominal unit costs. A second useful principle is that the division of labor in society should be respected. Those who are willing to bear risk for possible rewards should be hired for that purpose. The willing and efficient risk-bearer is worthy of his hire. Ratepayers are not professional risk-bearers. They should not be drafted into that role for the sake of creating a lower than otherwise attainable nominal price.

Regulated firms that want to create a sustainable allocation of risk will encourage and support regulators in honoring these two principles. In the 1960s, regulated firms and their financiers did not so encourage regulators. At a time when price setting and risk allocation initiatives were almost entirely theirs, they flouted these principles for short-term gains. In so doing, they created a risk allocation pattern that failed when tested. Their eager reaping of profits during the Golden Age created a fragile circumstance that cost some of them substantial sums in the 1970s and 1980s and clouds the investment picture for utility assets in the 1990s.

CONCEPTS AND PRINCIPLES OF WHEELING AMONG INTERCONNECTED UTILITY SYSTEMS

presented by

Allan J. Schultz
Executive Vice President
CASAZZA, SCHULTZ & ASSOCIATES, INC.

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The subject of "wheeling"1/, or the third party transmission of electric power and energy, is a matter receiving considerable attention in a number of arenas. In the United States, the matter has been for several years debated in a variety of public forums, including Congress, regulatory commissions at both the Federal and state levels, and in a large number of conferences and seminars. In Canada, the Government gave some recognition to the subject during the the inquiries that led to its electricity exports policy several years ago, and, currently, the National Energy Board has an investigation of the subject in progress. In Europe, questions are being raised relative to the use of the interconnected transmission systems of the members of the European Economic Community in anticipation of the events of 1992 leading toward the creation of a single European market.

The impetus for this strong interest in wheeling arises from an understandable desire to lower the cost of capacity and energy. A customer for electricity is motivated to purchase from the supplier(s) offering the lowest price and, if such supplier(s) are not directly interconnected with the customer, access to the intermediate utility's transmission system is necessary if there is to be a transaction. Similarly, a supplier of electricity is interested in the largest possible market, which may involve potential customers with which it is not directly interconnected.

It is to be understood that references to utilities, power systems, entities or agencies as distinct or separate identities relates only to ownership. No utility agency of any consequence operates in physical isolation. All power systems of the U. S. and

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1/ "Wheeling" is the use of the transmission facilities of one entity by two or more other entities whose transmission facilities are not directly connected with each other for the purpose of buying and selling, or interchanging, electricity between themselves.

Canada are interconnected into four large networks; each network operates internally in synchronism, and is connected to at least one other network asynchronously (through a direct-current link). The four networks are:

1) Eastern Interconnection (all systems east of the Rocky Mountains)

2) Western Interconnection (all systems west of the Rocky Mountains

3) Texas Interconnection

4) Quebec

Each of these networks electrically is a single system. The electricity responds only to natural physical laws without regard to the ownership of the facilities. The routing of power flows cannot be directed; power will flow over the transmission lines as determined by the physical parameters of the facilities.

Unfortunately, the transmission of electric power is a very complex technical phenomenon governed by physical laws that are invariant and which may interfere with the ability to engage in commercially attractive power purchase arrangements. These technical considerations are not always understood by those whose involvement in the current efforts to establish a new regime for electricity supply originates from a political or a theoretical economics point of view. They often erroneously equate electric transmission with commodity transmission systems such as gas, water and oil pipelines.

"The transmission network is the 'glue' that allows the system to be a system and makes the whole arrangement work. In addition to the delivery of electricity from the generating stations to the distribution substations, the transmission network integrates all the generators and loads into a coherent and economic whole. This integrating function is not well appreciated, but it is the basis for the important economic benefits of coordinated operation." [IEEE United States Activities Board, November 1989]

Physically, the operation of an electric system is a highly precise "balancing" act. The rotating elements of major electric generating units are massive; the rotor of each generator that is connected to the system must rotate at exactly 60 rotations per second (or the equivalent for machines with multiple pairs of poles). For a generator to rotate at exactly synchronous speed, the mechanical power supplied to the turbine (by steam, falling water or hot gases) must exactly balance the electrical power load on the generator. While the electrical load can be changed almost instantaneously (the opening or closing of a circuit breaker can interrupt or establish the electrical current in a cycle or two), the ability to adjust the mechanical driving power takes much longer. As a result, changes can occur on the transmission system which increase or decrease the electrical load on the generators, causing the generators to rotate more slowly or faster; if not carefully controlled, generators in this situation can lose "synchronism" and have to be taken out of service instantly.

The controllers of the power systems constantly are alert to respond to events which could result in imbalances which would interfere with, or interrupt, the continuous supply of electric power to all customers. The simplest unbalancing circumstance is that of changes in electrical load as customers turn on lights, appliances. tools, industrial processes, etc. Even the largest such change is generally quite small in relation to the power being supplied, and load changes tend to occur as part of a regular daily pattern, and can be anticipated. System control in response to load changes is, therefore, routine - albeit complex -provided the controller has control over all the power sources and the transmission system in his control area. Some new generating facilities, however, are owned and operated by non-utility entities and are not subject to dispatch and control by the system controllers; similarly, power that is to be wheeled over a utility's system is under the scheduling control of the seller and/or buyer. In these situations, the area controller (dispatcher) has to cope with power flows on his system of which he may be unaware and unable to control.

Changes on the electrical system resulting from equipment failures and system disturbances are a much more serious threat to the continuity of power supply. Electrical generators are complex assemblies of hundreds of components in which materials are stressed almost to their physical limits. Failures occur that require the generating facility to be removed from service as soon as possible (in one-twentieth of a second, or so) to prevent serious damage to the equipment. Transmission lines are geographically extensive and are exposed to lightning, winds, falling trees, frustrated hunters, etc. which could, at any time, result in any line being removed from service automatically.

For these reasons, the primary criteria for the design and operation of electrical power systems is reliability; economy of operations is a secondary consideration. To provide for the reliable design and operation of power systems, the utilities of the United States and Canada have voluntarily formed the North American Electric Reliability Council (NERC) and the underlying nine regional reliability councils. Every major electric utility agency in both countries is a participant in the appropriate regional council and NERC.

As pointed out above, the key to reliable operations is for the area controllers to have complete control over the facilities and the power supply affecting the loads and customers for which they have responsibility. Wheeling of power arises from economic considerations which, under certain circumstances which could easily be in conflict with the reliability factors.

Even if the utilities engaged in the power transaction have contracted for wheeling services, they can cause power to flow on the transmission system of the wheeling utility over which the system controller may lack control, or even have no knowledge, unless there are special communications arrangements.

A more important consideration results from the fact that power flows over interconnected transmission systems are determined by physical laws. Among power systems that have a multiplicity of interconnections with each other, the phenomena of "parallel path" and "loop" flows can occur. These are different aspects of the consequences of physical laws. Parallel path flows occur when power scheduled from a utility's own internal generation is dispatched to supply that utility's load, but some of the power actually flows over a neighboring system's transmission system. Loop flow occurs when a utility schedules power for delivery to a neighboring utility but the power flows over the transmission systems of other utilities rather than over the facilities of the utilities involved in the transaction.

Because parallel path and loop flows occur without the knowledge of the controllers of the area in which they occur, reliability as well as economics may be affected. Loop flows, if they are additive to power flows resulting from the owning utility's power dispatch can result in transmission line overloads, in increased voltage drops and in increased system losses.

As an example, **Slide 1** depicts a well-known case of parallel path flow. Shown are the actual power flows that resulted when Ontario Hydro generated 1,000 Megawatts of power for delivery to the utilities of the New York Power Pool. Even though the Ontario Hydro system has interconnections in several places with the New York utilities that together have sufficient capacity to transmit the power, only 500 Megawatts flowed over the desired transmission facilities; the other 500 Megawatts flowed to the west, over the systems of the Michigan utilities, and thence through the systems of the Ohio utilities, American Electric Power and the Pennsylvania utilities to reach New York. Such flows interfered with the ability of these utilities to transmit their own power for their own loads.

Reliability requires utilities to keep some transmission capacity in reserve against the outage of important circuits. This imposes a limit to the amount of power that can be transmitted under normal conditions, if the systemm is to remain functioning during emergencies. This is demonstrated in **Slide 2**. Assume a system of three transmission lines, each of which is capable of transmitting 100 Megawatts (thermal limitation) but because of other factors (i.e., line lengths, conductor configurations, etc.) they divide the total power flowing between their common terminals in the ratios of 10:9:8. As shown in figure (a) of Slide 2, if the power being transmitted is an amount that just loads Line A to its limit, Lines B and C will be transmitting 90 Mw and 80 Mw, respectively. This will cause no problems as long as all three lines are in service. But, suppose Line B "trips" out. As shown in figure (b), the total amount of power will divide in the ratio of 10:8 and both lines will be overloaded; adjustments to the system operations will be required to prevent damage to the lines. The highest normal (no outages) loading is that shown in figure (c) because if the system loses Line B the remaining lines can transmit the pre-outage power without adjustment, as shown in figure (d).

Wheeling is not a new concept; major utilities have been wheeling power for each other for over 60 years. The physical problems that occurred were worked out among the utilities involved, the trend being towards increased coordination of operations. Over the last ten years, however, there have been other entities of a different nature wanting access to the transmission systems. Municipal utility agencies have formed joint operating agencies (pursuant to new legislation) under whose umbrella they are developing their own power supplies. These agencies need to use the transmission systems of the utilities who formerly were their total suppliers to deliver their own power resources to their members. Another group asking access to the transmission systems is the non-utility generators. Belonging to this group are co-generators and small power producers, which have arisen under the encouragement of the Public Utility Regulatory Policies Act (PURPA), and a developing class of Independent Power Producers. These entities develop generation which they will sell to any purchasers on a competitive basis. Finally, certain large industrial users wish access to the transmission system so they may purchase power from suppliers other than the utility to which they are connected.

Power systems have not been designed to receive power at all locations or to deliver unknown amounts of power to any place on the system. The problem of whether or not a particular wheeling proposal can be accommodated on an existing system requires an engineering analysis to determine the consequences on system operation. Necessary information for the conduct of the analysis includes the answers to four questions:

1) How much power is to be wheeled?

2) Where is the source of the power located on the interconnected systems?

3) Where is the load to which the power is to be delivered located?

4) At what times is the power to be delivered?

With this information, system analysts can make studies of the system's performance with and without the proposed transaction, and determine what additional facilities may be required to make the proposed transaction workable.

Requests for transmission access are not always based on a point to point delivery of power as suggested by the above questions. There are many requests which are, in reality, not wheeling but rather requests for an entitlement in the capability of the entire transmission system; the desire is to be able to purchase power from any of several possible suppliers at diverse locations and at arbitrary times depending on spot price quotations. A transmission system cannot respond to such a request without studies of essentially all combinations of the proposed transaction superimposed on the utility's own load and generation patterns.

Recognizing the need for studies of the impact of proposed wheeling arrangements, some utilities have recently filed tariffs with FERC which include as a necessary step the conduct of appropriate studies at the customer's expense.

There are a number of problems related to wheeling for which satisfactory policies have yet to be established. One such matter arises from the opportunity presented by wheeling for one entity to compete for, and purchase, the output of generation that previously had been sold to a different purchaser. While in total there might be no change in the cost of providing energy to the entire load, there may have been a shift in costs among the individual buyers. In short, wheeling has permitted a situation where one customer benefits at the expense of another. Is that good policy? Another situation occurs when an existing system may be able to accommodate the wheeling of a certain amount of power under defined conditions. If there are competing applications, one of them may be within the capability of the system, but two may be too large. How to decide which applicant should be selected? Losses are also a problem. Because losses increase with the square of the increase in power transmitted, the incremental losses associated with a wheeling transaction are likely to be proportionately higher than the losses associated with those of the power delivered to the utility's own customers. But, is the wheeling transaction to be treated on an incremental basis?

Probably the most difficult problem arises when additional facilities are required, totally or in part, to provide wheeling services. Consideration of the addition of new facilities suggests a long term commitment for the wheeling. If the additional facilities are clearly identifiable with the wheeling transaction, the cost of such facilities are appropriately to be recovered in the price for the services. The need for a transformer or a circuit breaker at the point of interconnection of the source or the load, for example, is quite specifically related to the wheeling service. A new transmission line, or substation enlargement at a location remote from the input or delivery points of the wheeled power, however, may be due to system load growth as well as the addition of wheeled power. There is no consensus relative to the allocation or assignment of costs for new transmission facilities.

The pricing for firm wheeling services is another part of the problem having more controversies than solutions. There are a number of pricing mechanisms in use in different applications and areas, all of which appear to be working satisfactorily. One of these methods is the so-called "postage stamp" approach. An embedded transmission cost of service is determined. Dividing this total cost by the amount of peak power handled by the system, including the power to be wheeled, results in an average unit power cost which becomes the price to be charged for transmission services. This approach gives no weight to distance as a factor - customers close to power plants or substations are charged the same as customers more remote. Implicit in the method is the assumption that the customers are not responsible for the amount or length of transmission serving them; customers do not give any attention to the distance they are from utility facilities when locating their homes or businesses. Therefore, distance or location is not a factor to be recognized in establishing prices under this method and no analysis is required to identify the specific facilities actually used by the wheeled power at any time. Postage stamp firm transmission rates are calculated the same way cost of service studies are made for rate making and do not require any special cost studies. The fact that the wheeled power may cause problems on specific facilities is ignored as well as the fact that part of the power to be wheeled may show up as parallel path flow on a neighboring system. The fact that the wheeled power may flow in the reverse direction from normal power flows, thus reducing line loadings and creating a benefit, is also ignored.

Another common approach to pricing firm wheeling is the "contract path" method. This method imputes a transmission path that the wheeled power will follow. The price for the service is based on the costs for that specific line. The actual power flows have no relationship to the transmission path chosen. Wheeling is continued when facilities that are in the contract path are out of service even though other facilities necessarily are being used and which are not taken into account when the price is calculated. And, parallel path flows on neighboring systems are also ignored.

Similar to the contract path approach is the "phantom line" method. This method is based on the assumption that if the transmission system did not exist, the buying and selling parties needing the wheeling could build their own transmission line. The price for the service is based on the cost of an imaginary line. That a single line cannot provide firm transmission service is given no attention. This method also has the infirmities of the contract path method.

In some areas, pricing for firm wheeling is based on a demand-distance, or system use, procedure. The method depends on power flow analyses in which the various services are measured individually to determine how much of the power involved actually flows over each separate transmission line. The amount of power flowing in each line is multiplied times the length of that line and totalled for each different service. Costs are assigned to each service in relation to their contribution to the total megawatt-miles. This method does identify and assign costs to parallel path flows. It does reflect actual use of the transmission system although use is measured at only one time during the year - generally at the system peak.2/

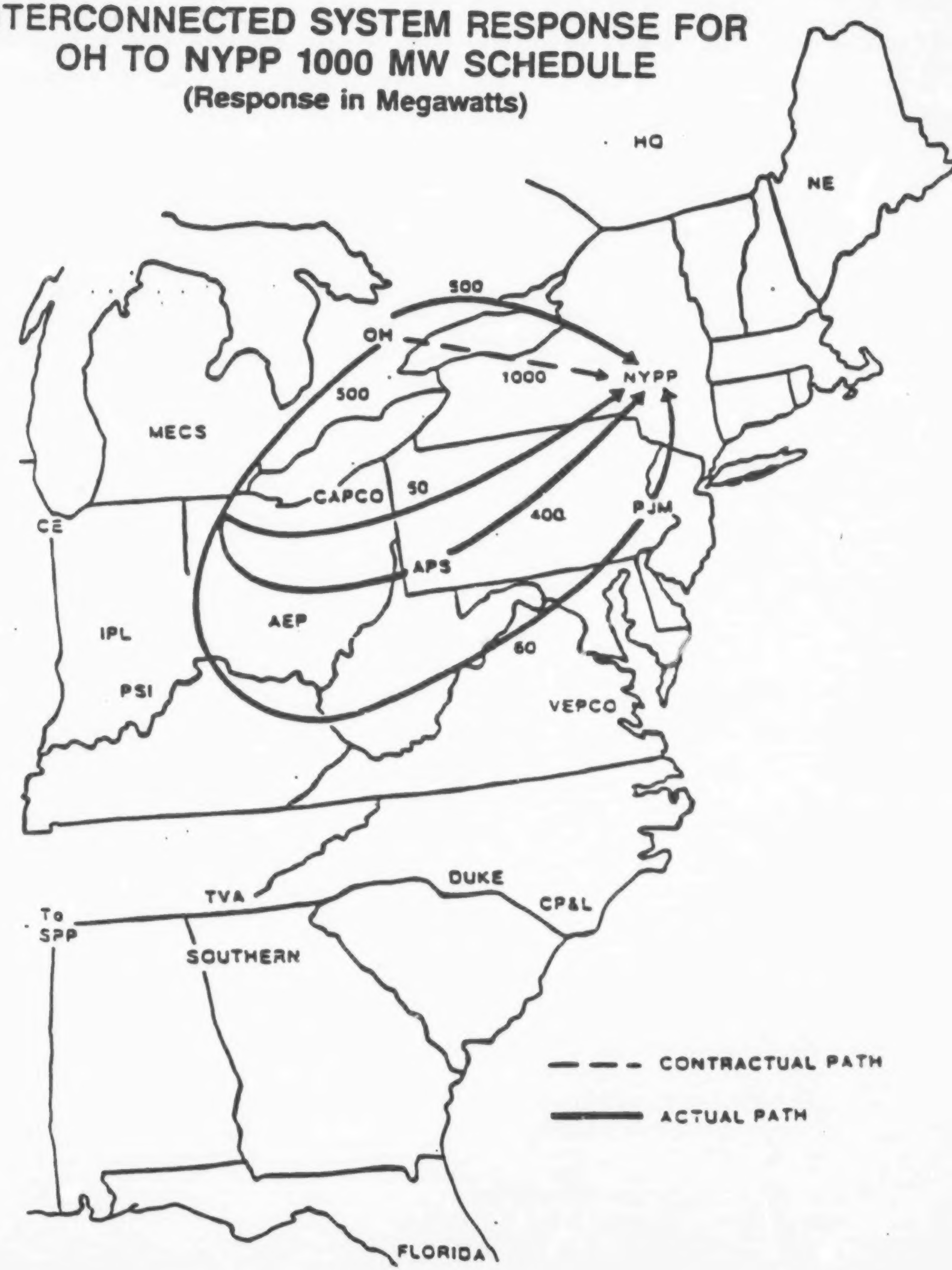
Other methods include charges based on the cost of the power being wheeled (this is applicable both to firm and non-firm power). A similar method bases the wheeling charge on savings gained by the buyer and seller when non-firm power is being wheeled. In other situations, wheeling prices are set by negotiations among the parties.

As discussed above, there are a number of problems associated with the wheeling of electrical power. In addition to technical considerations fundamental to the operation of power systems, there are also policy and pricing matters. Some proposed solutions reflect the sponsors' interest in improving the economy of power supply but give no attention to the technical problems that are involved. There are satisfactory wheeling arrangements in practice but these have a wide diversity of methodology and procedure. In short, there are many proposals but nothing approaching a consensus with respect to wheeling arrangements.

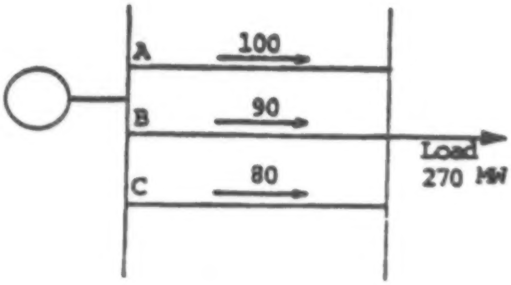
2/ Computer facilities and analytic techniques have been developed to the point where the distribution of power flows on the components of a transmission system can be determined by source on a continuous basis. As a result, it is technically possible to develop a transmission pricing method related to actual use of the system. Whether this is desireable or economically feasible has yet to be determined. See New Methods For On-Line Determination of Transmission Use and For Developing Transmission Utilization Indices, P.J. Palermo, R.H. Iveson, D.J. Heltemes, CIGRE Paper 38/39-04, 1990

INTERCONNECTED SYSTEM RESPONSE FOR OH TO NYPP 1000 MW SCHEDULE

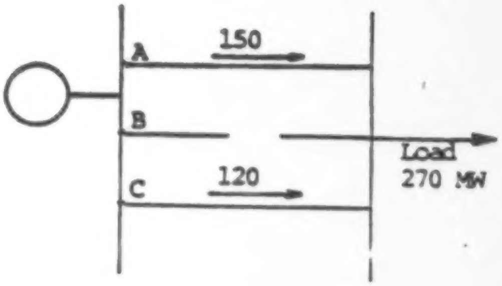
(Response in Megawatts)


HQ
NE
500
OH
1000
NYPP
500
MECS
CAPCO
50
400
PJM
CE
APS
IPL
AEP
60
PSI
VEPCO
DUKE
TVA
CP&L
To SPP
SOUTHERN
FLORIDA
CONTRACTUAL PATH
ACTUAL PATH

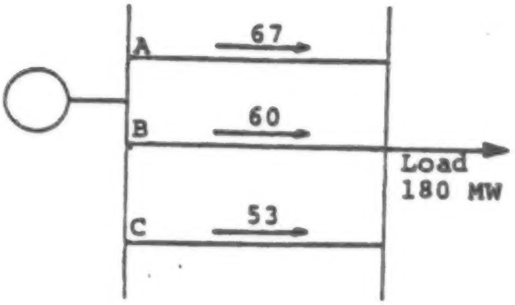
TRANSMISSION SYSTEM LIMITATIONS
(ALL LINES RATED 100 MW)


A
100
B
90
C
80
Load
270 MW

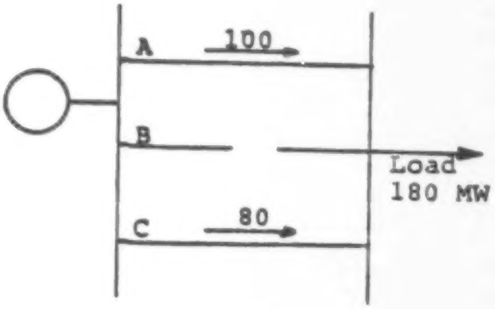
(a)
All lines in service.
System loaded without considering contingencies.
Line A at rated loading.


A
150
B
C
120
Load
270 MW

(b)
Outage of Line B
System loaded without considering contingencies.
Lines A and C overloaded.


A
67
B
60
C
53
Load
180 MW

(c)
All lines in.
System loaded to "n-1 contingency limit"


A
100
B
C
80
Load
180 MW

(d)
Outage of Line B
System was loaded to "n-1 contingency limit" before Line B tripped.
Line A at limit. No overloads.

ENHANCED INTERPROVINCIAL TRADE: OPPORTUNITIES IN WESTERN CANADA

Presented by

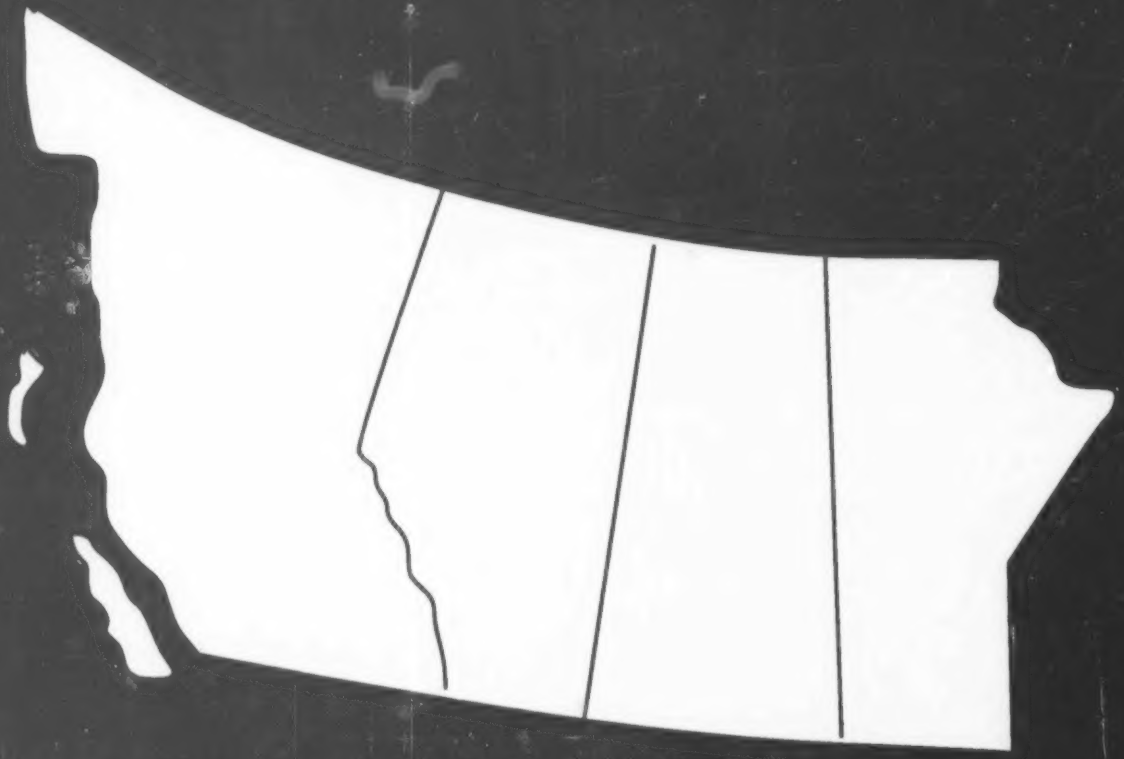
Mr. Walter Saponja
Senior Vice President, Operations
TransAlta Utilities Corporation
Calgary, Alberta

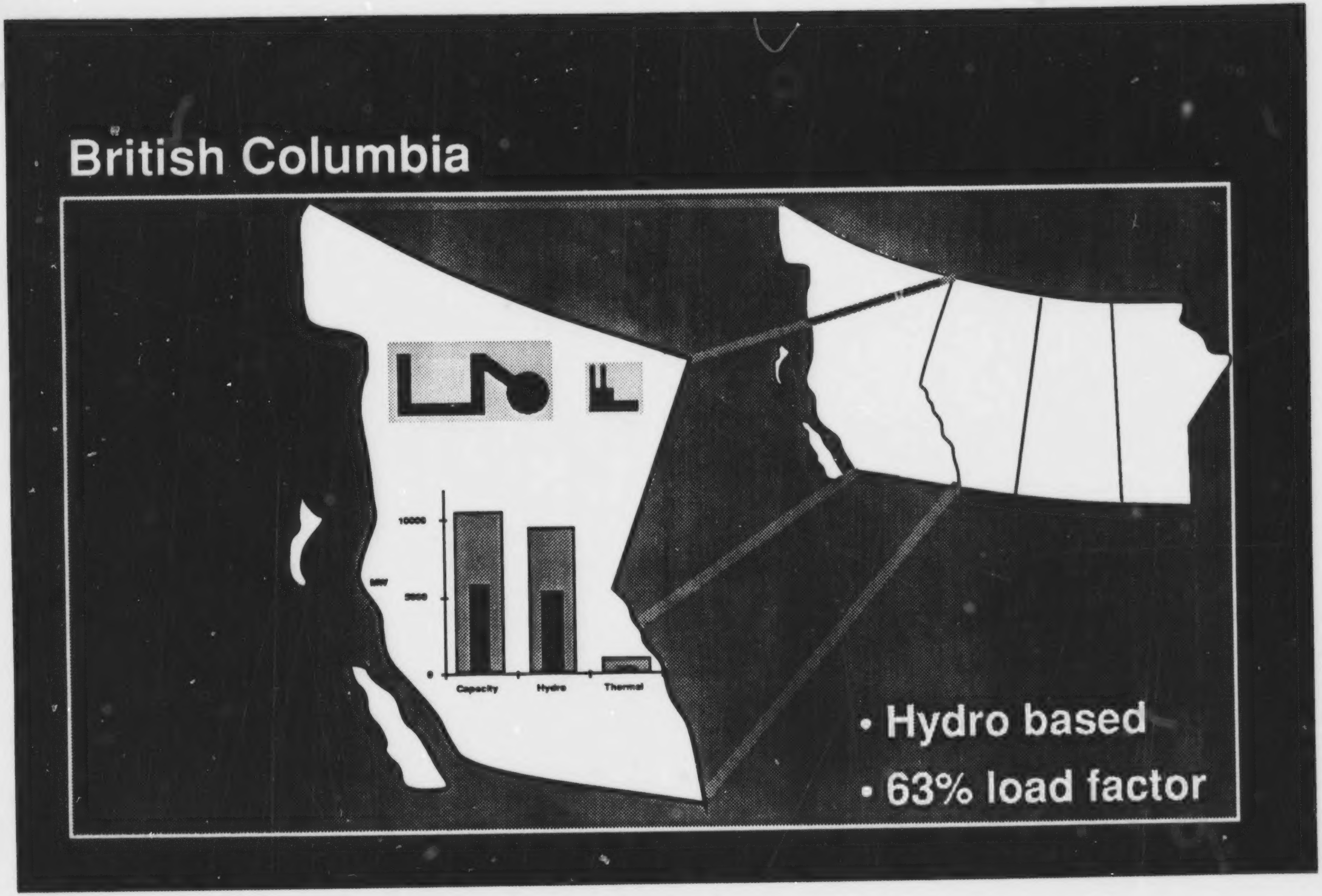
Presented to

Energy and Electricity: A Conference on Electric Power Planning in the 1990s

Montreal, Quebec
June 3-5, 1990

Interprovincial Electric Trade Opportunities in Western Canada



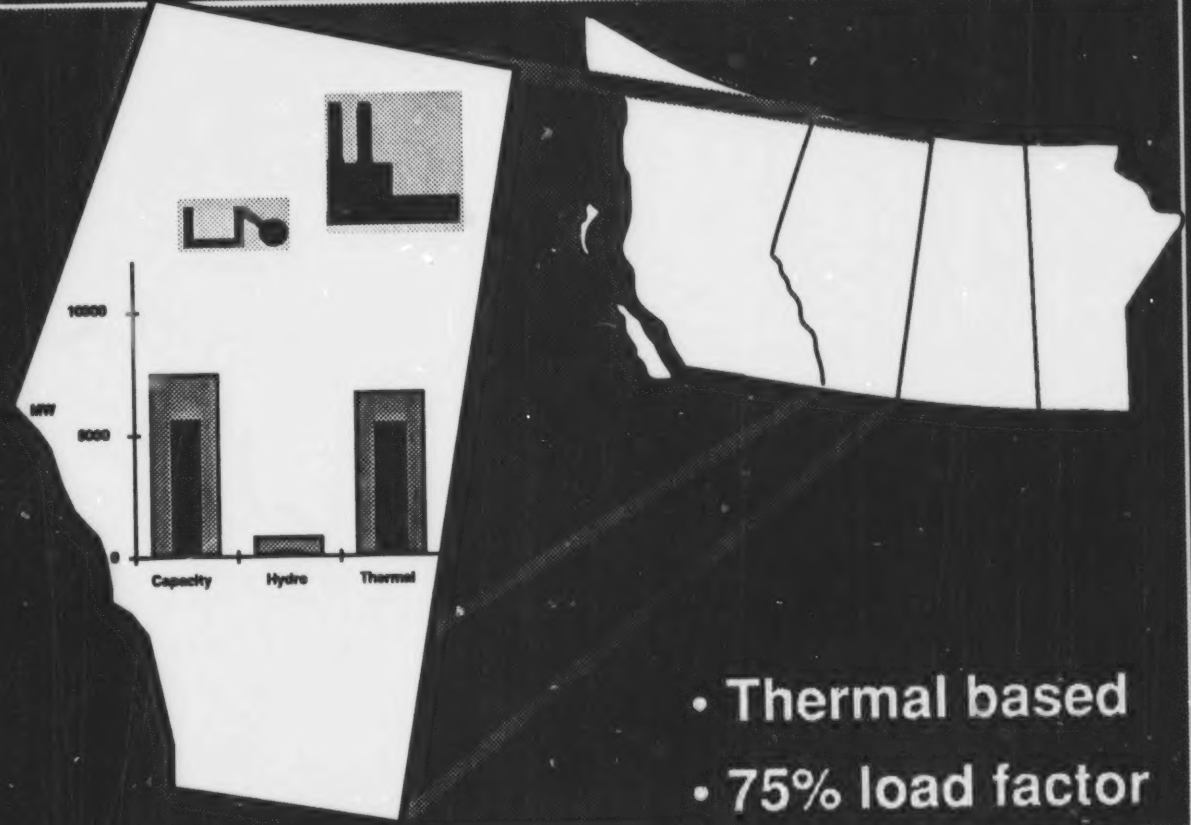


British Columbia

MW
10000
5000
0
Capacity
Hydro
Thermal

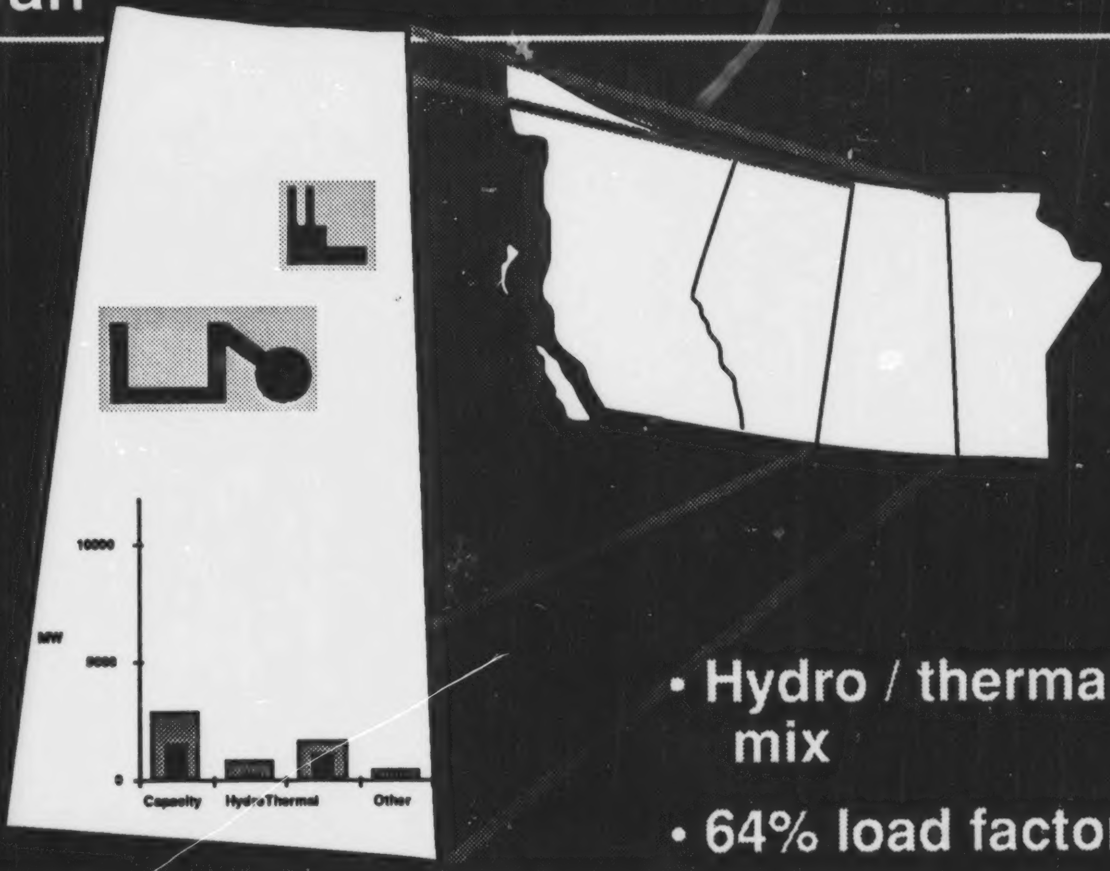
- Hydro based
- 63% load factor

Alberta



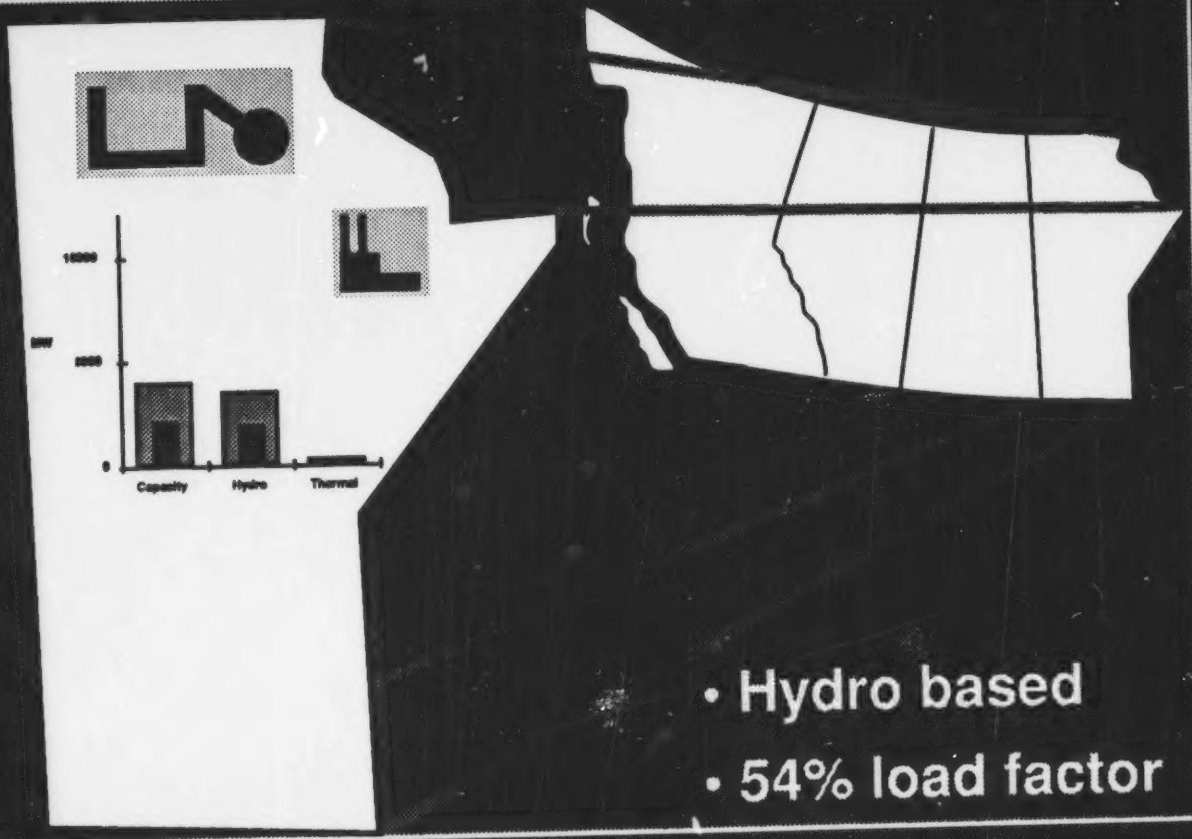
- Thermal based
- 75% load factor

Saskatchewan



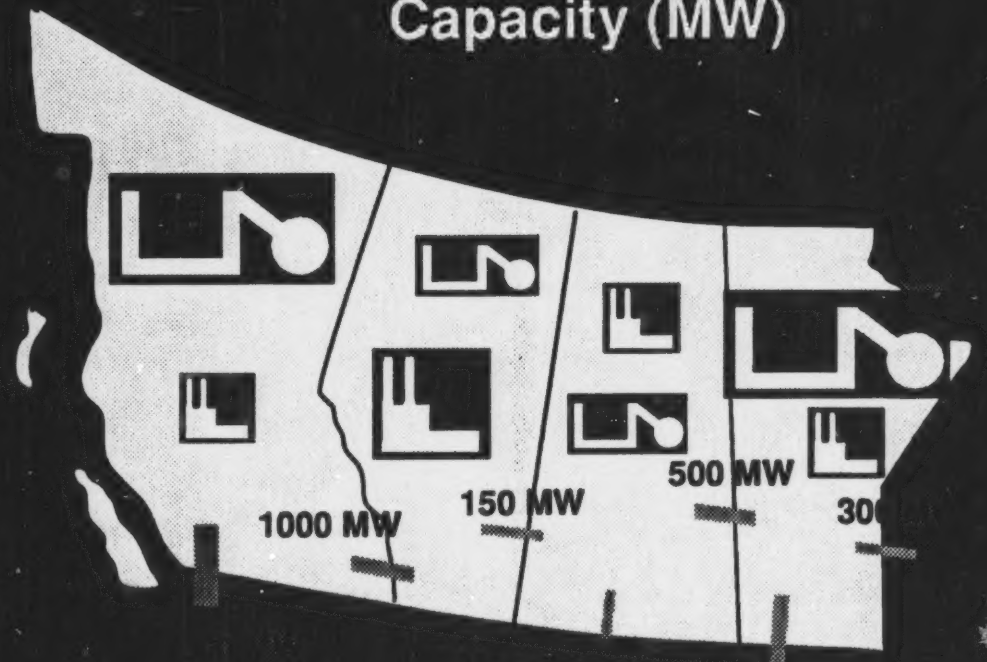
- Hydro / thermal mix
- 64% load factor

Manitoba


10000
MW
5000
0
Capacity
Hydro
Thermal

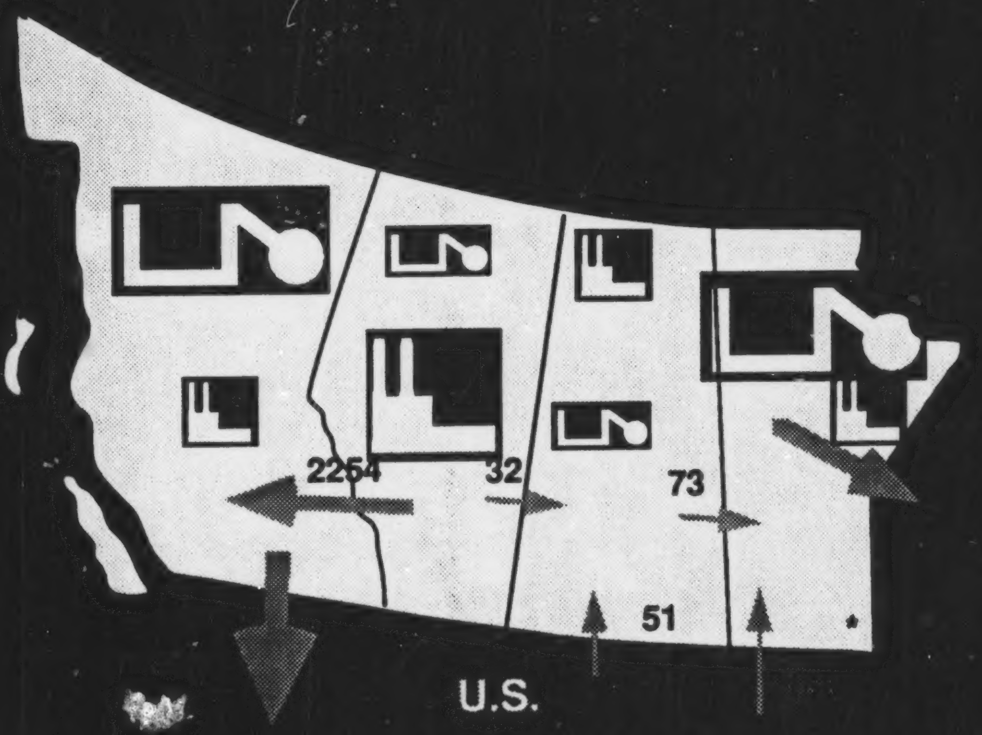
- Hydro based
- 54% load factor

Western Canadian Interconnections



Capacity (MW)
1000 MW
150 MW
500 MW
30

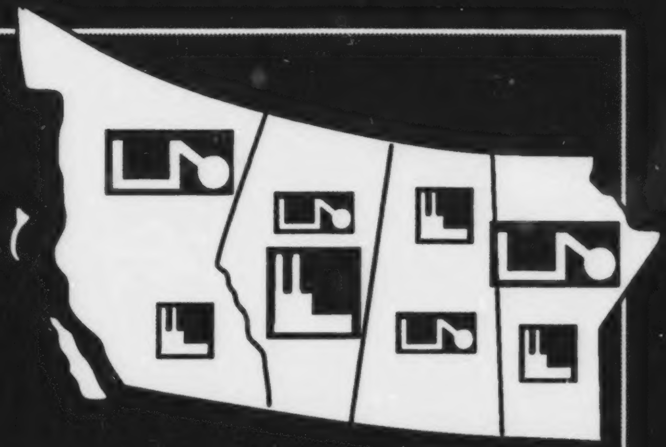
Western Canada Interprovincial and International Power Flow (1989 GWhr)


2254
32
73
51
*
U.S.

* for fiscal year ending March 31, 1990

2

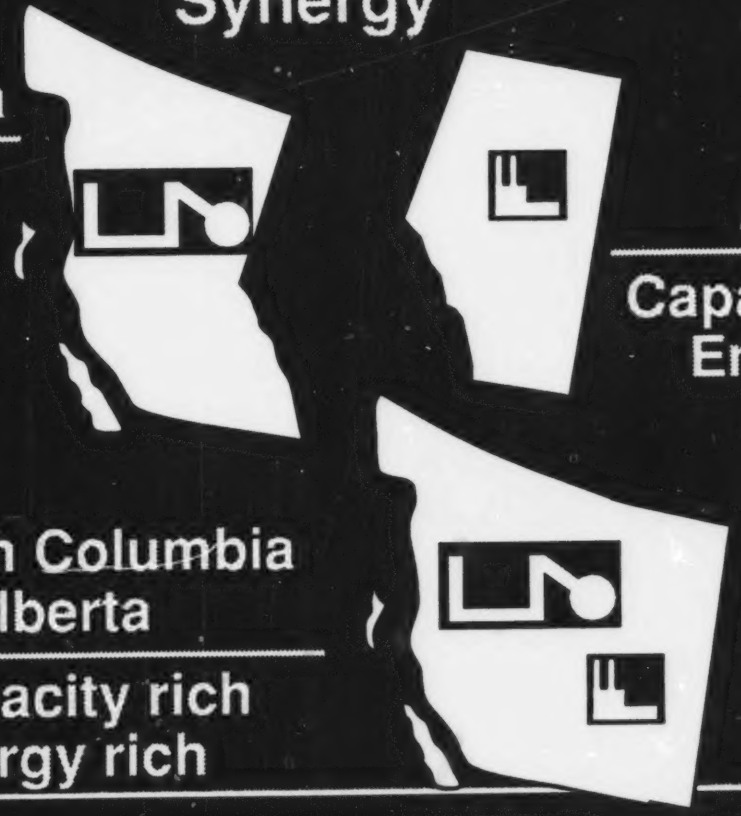
Planning Opportunities



Synergy

Definition - "combined effect of ... that exceeds the sum of their individual effects."

Planning Opportunities



Synergy

British Columbia

Capacity rich
Energy limited

Alberta

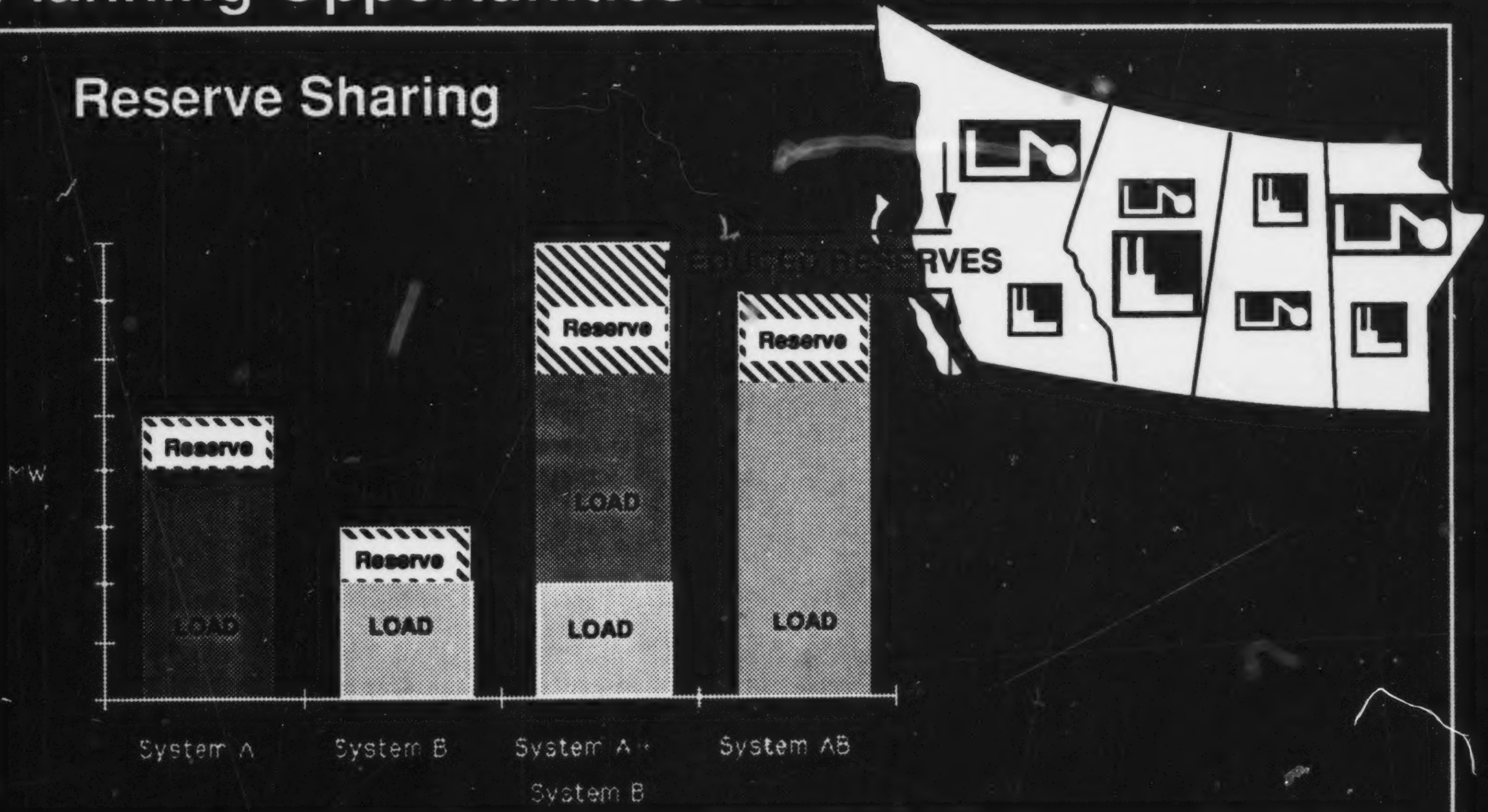
Capacity limited
Energy rich

**British Columbia
and Alberta**

Capacity rich
Energy rich

Planning Opportunities

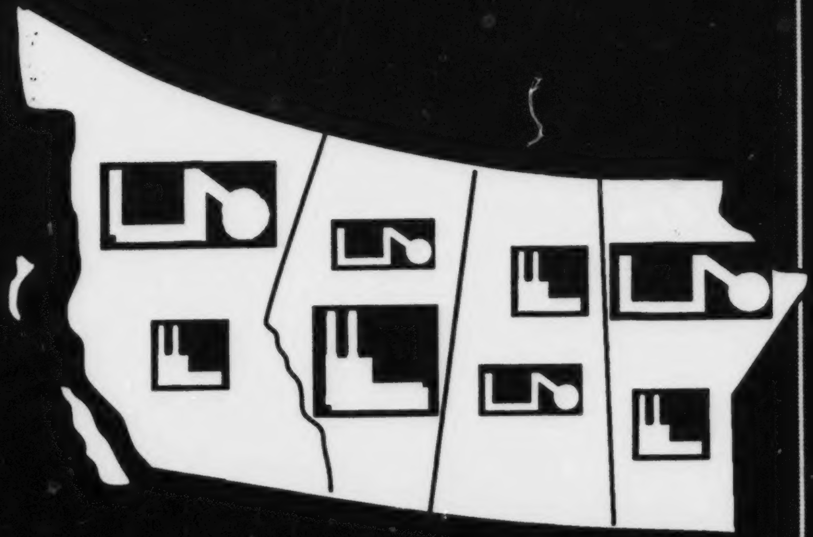
Reserve Sharing



Planning Opportunities

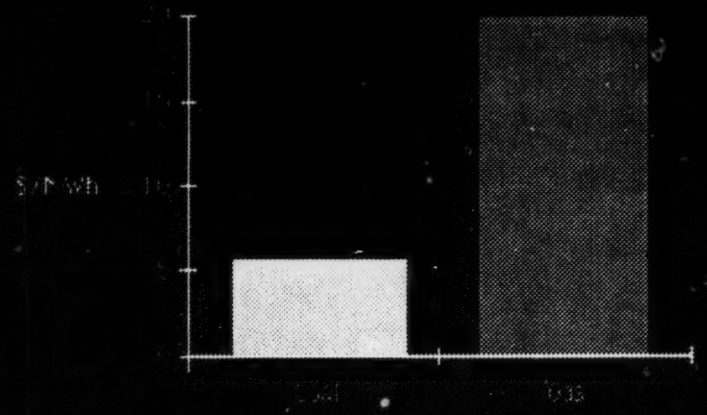
Lower Cost Generation Sources

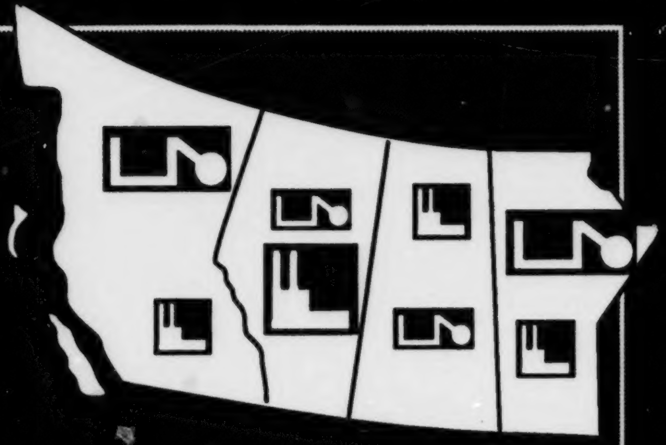
- Capacity additions at existing hydro sites
- Capacity additions at thermal sites



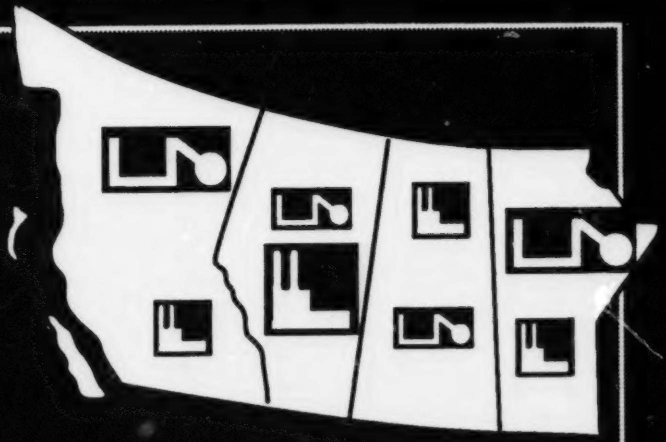
Operating Opportunities

Lower Fuel Prices





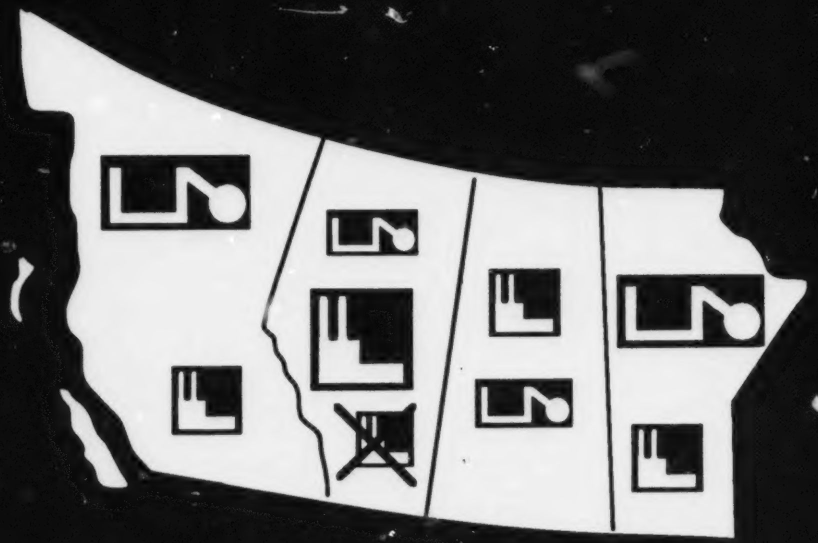
Capturing Opportunities



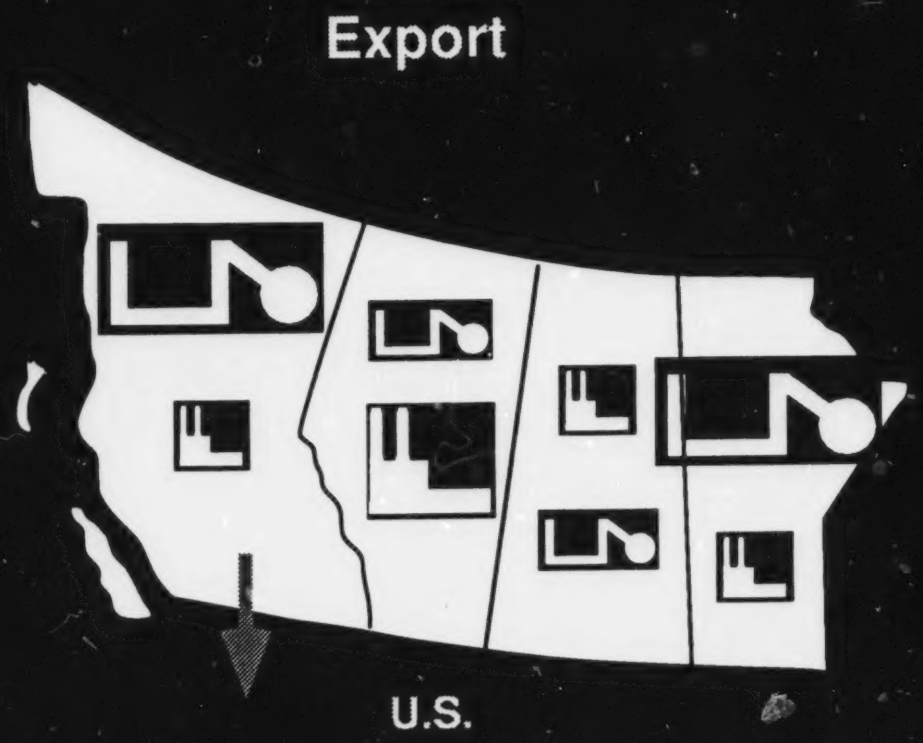
- Synergy
- Reserve sharing
- Lower Cost Generation Sources
- Lower Operating Cost

Synergy

Defer future plant

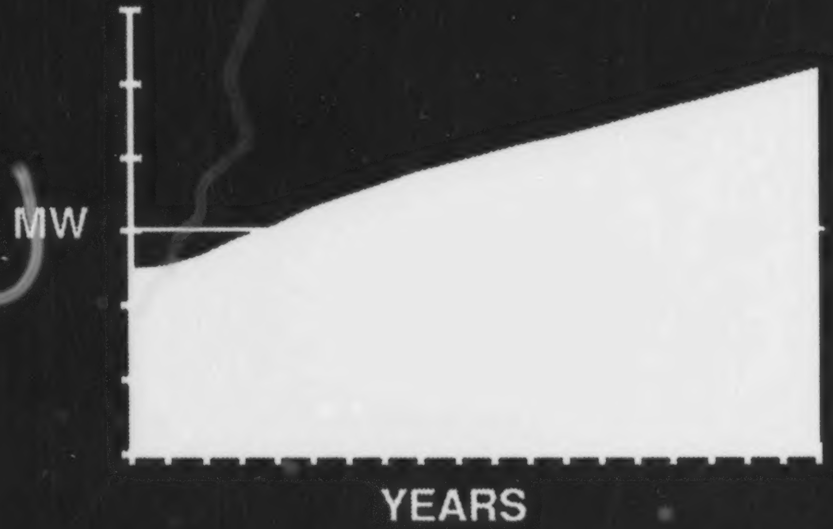


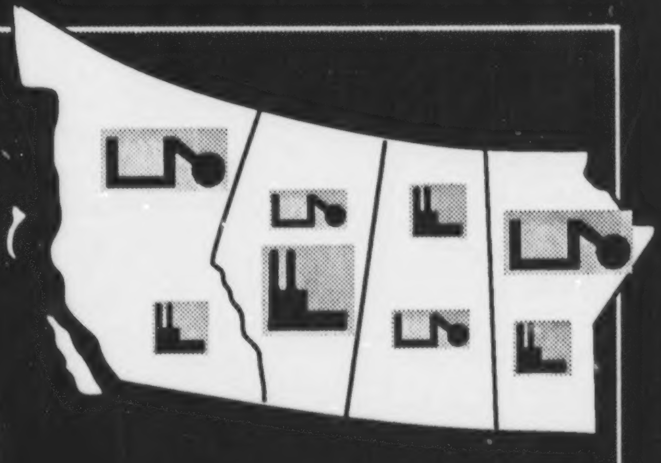
Synergy



Synergy

Planning Flexibility

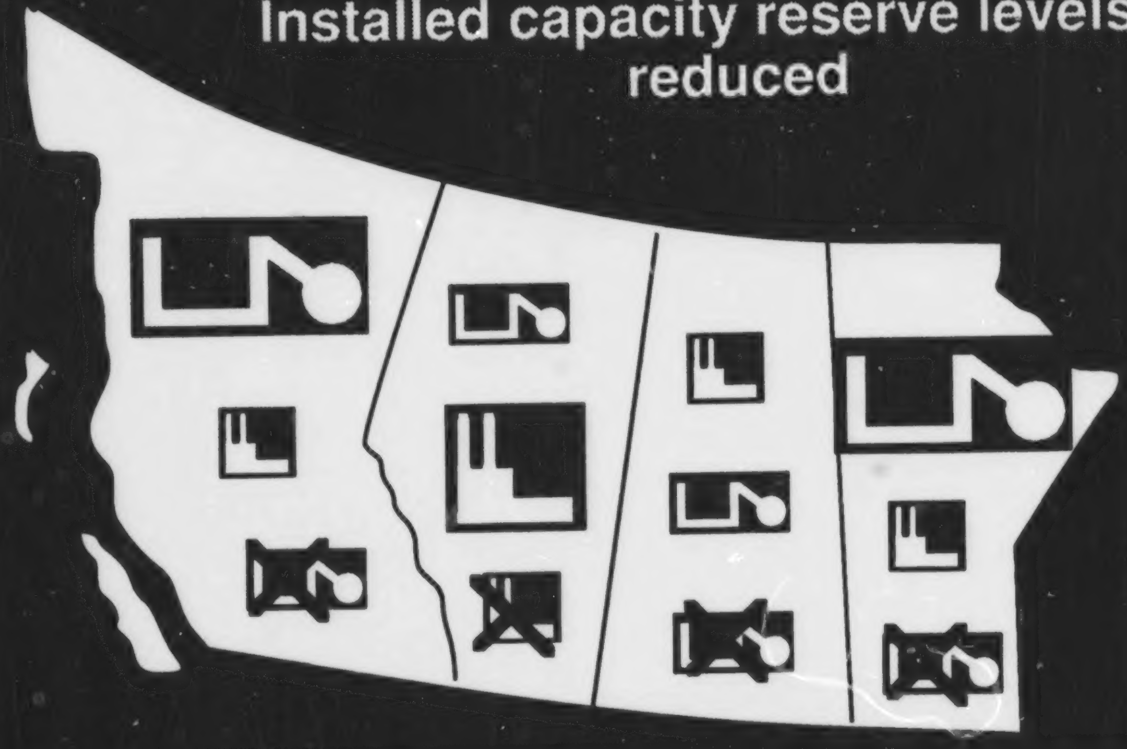




- Short lead time advantage

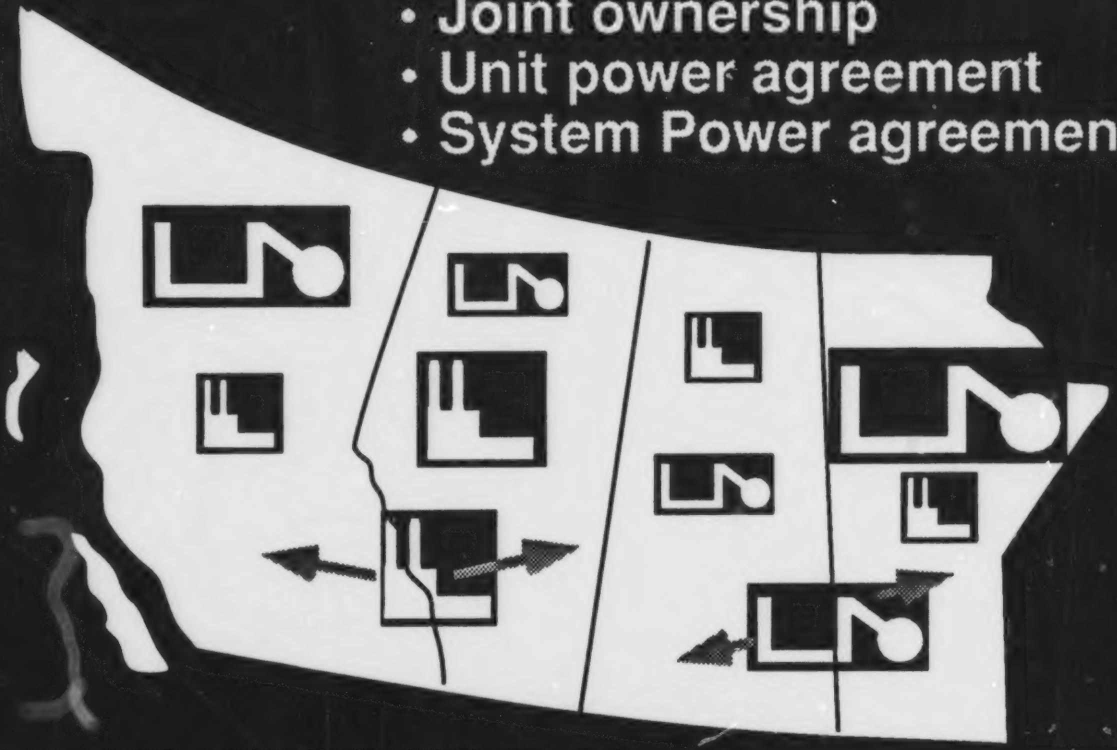
Reserve Sharing

Installed capacity reserve levels reduced

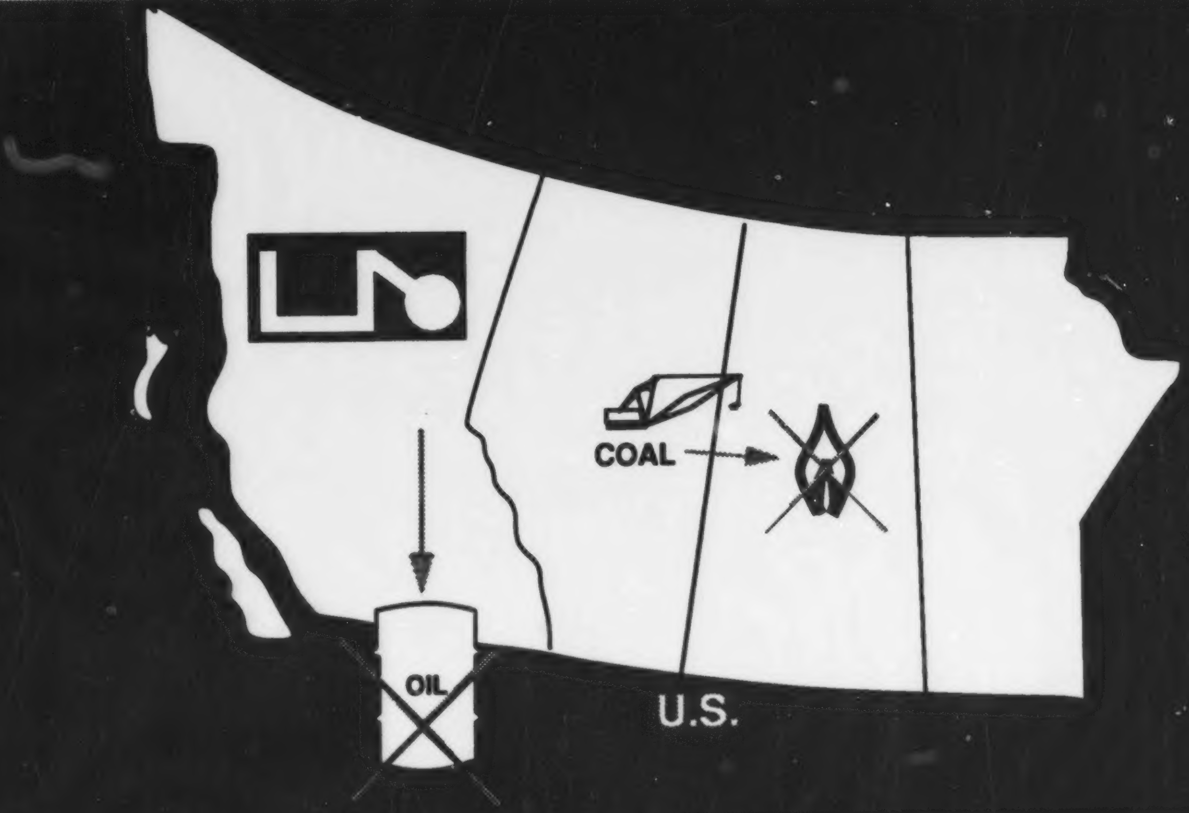


Lower Cost Generation Sources

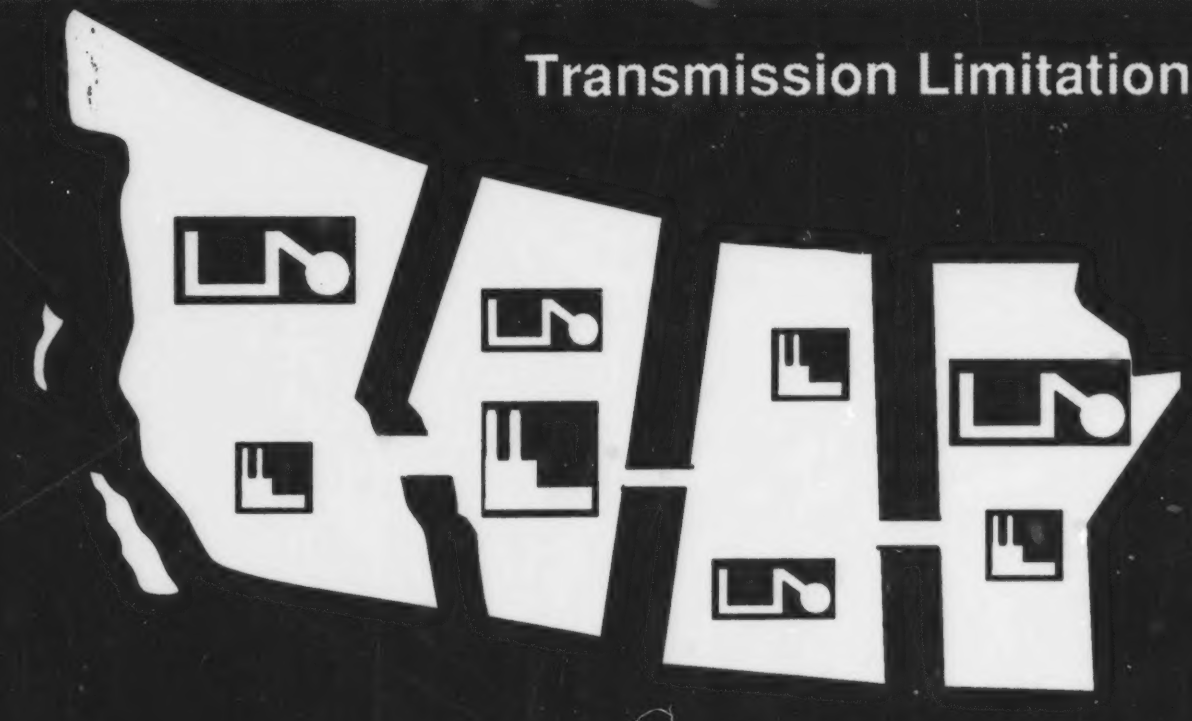
- Joint ownership
- Unit power agreement
- System Power agreement



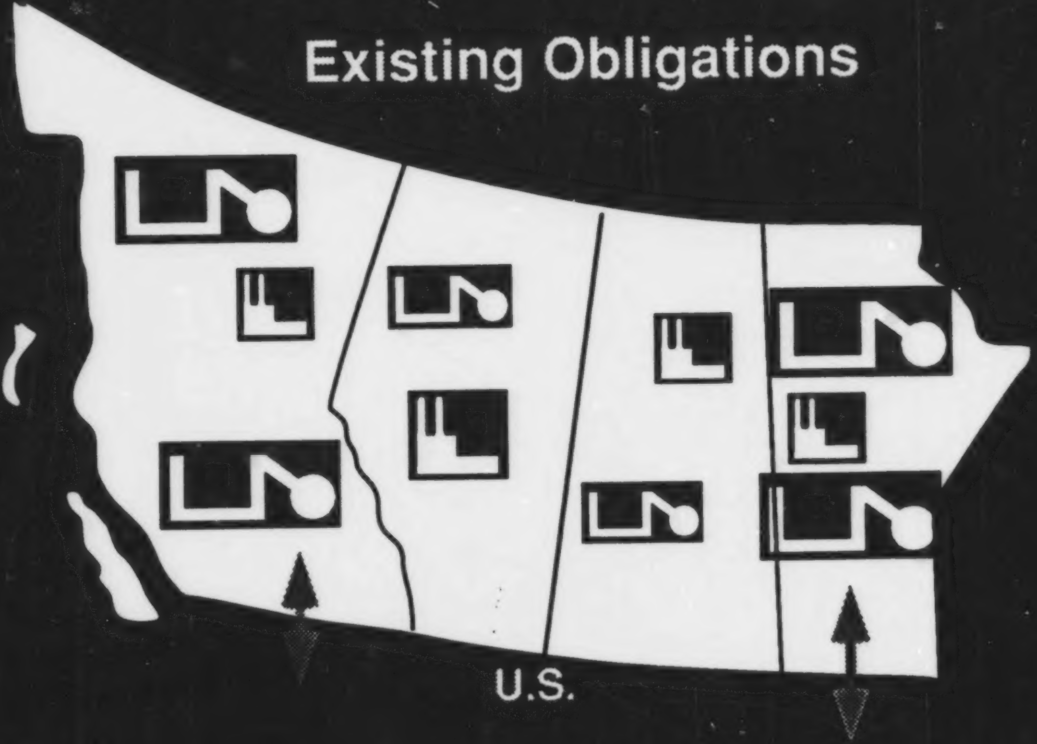
Lower Operating Costs



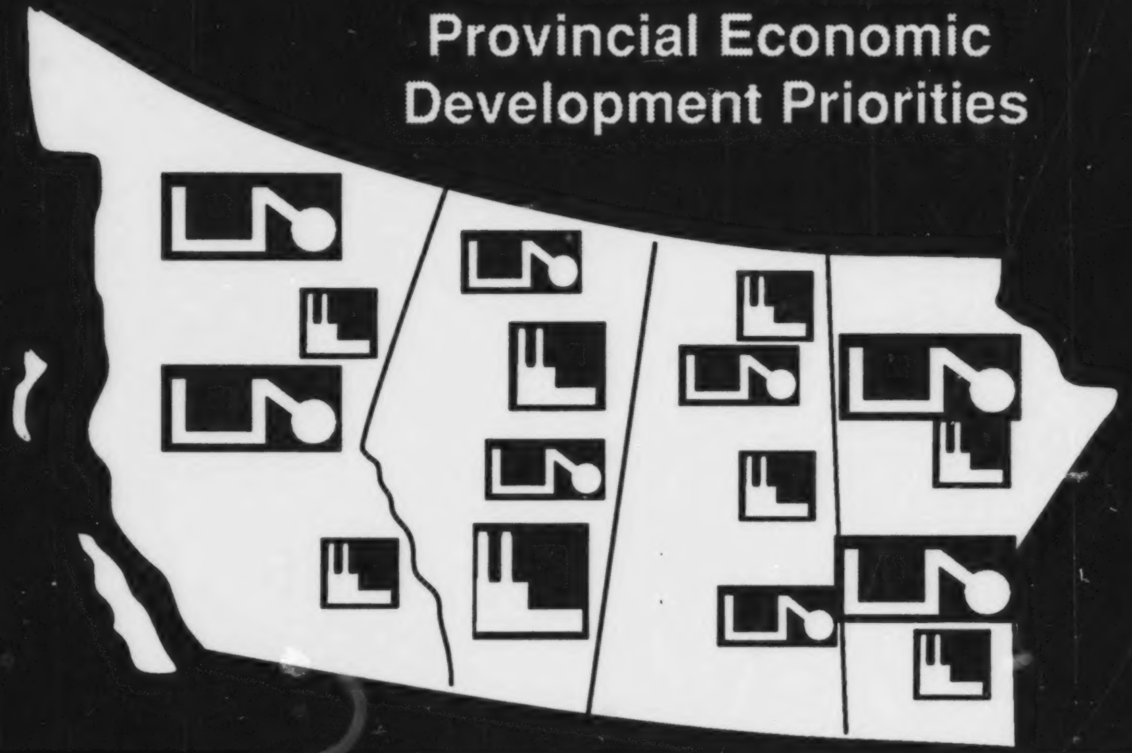
Obstacles


Transmission Limitations

Obstacles


Existing Obligations
U.S.

Obstacles



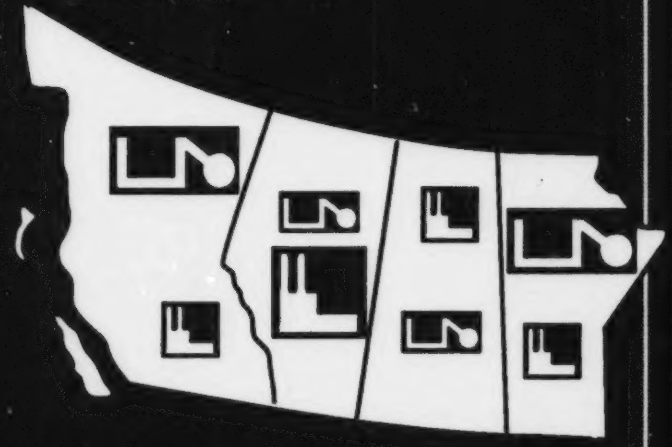
Provincial Economic Development Priorities

Obstacles

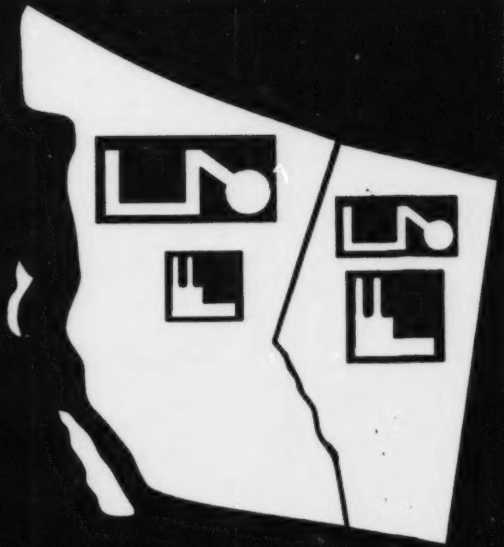
Regulatory Requirements

Obstacles

Complex Business Arrangements
- Long term commitments required



Current Initiatives in Western Canada

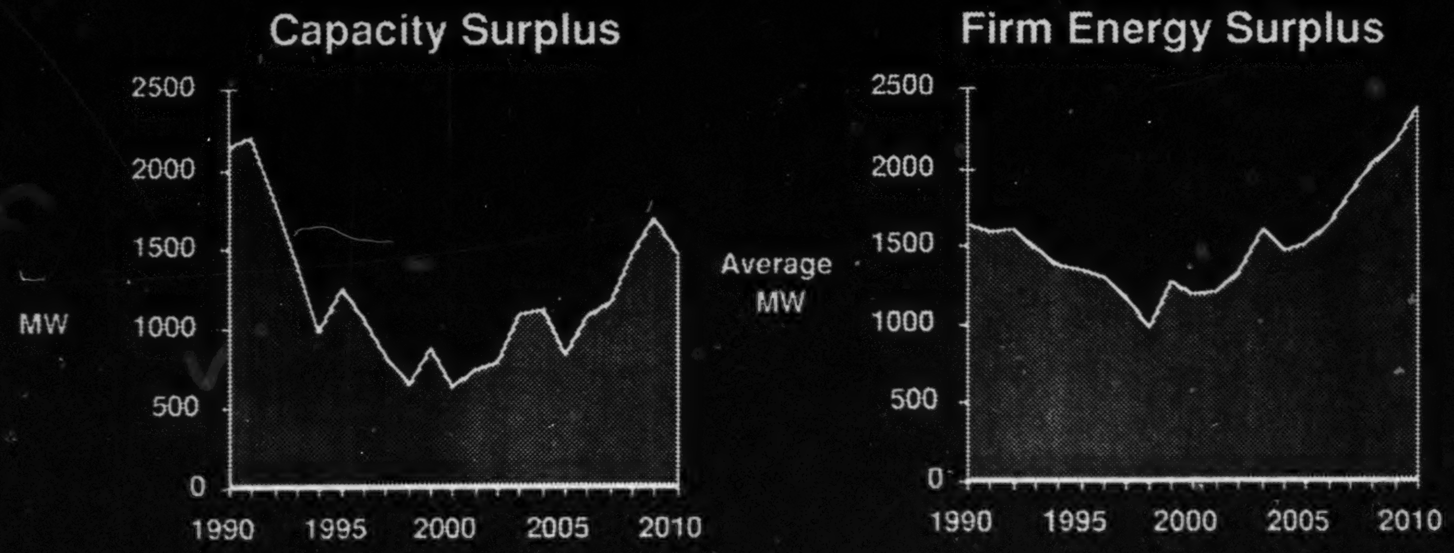


Alberta / British Columbia

- Phase 1 study complete 1989
- Phase 2 study complete 1990

Alberta / British Columbia
Phase 1 Study

Option 1
Combined B.C. Hydro / A.I.S. Surpluses



Capacity Surplus

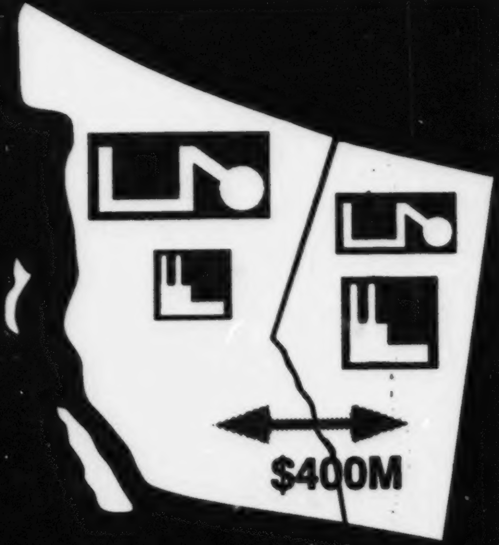
Firm Energy Surplus

Current Initiatives in Western Canada

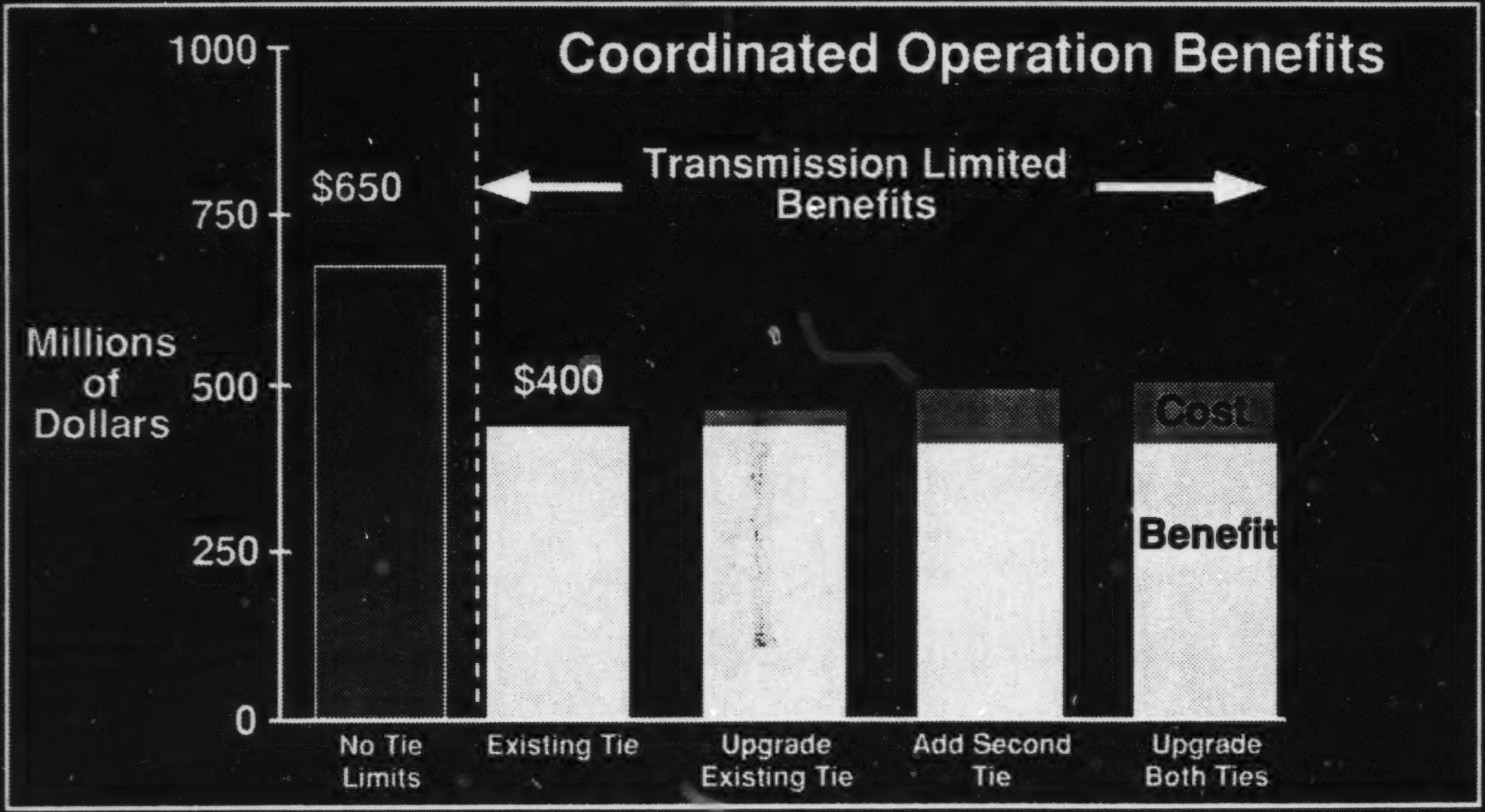
Alberta / British Columbia

Phase 2 Study

- 20 year period evaluated
- $400M benefit identified



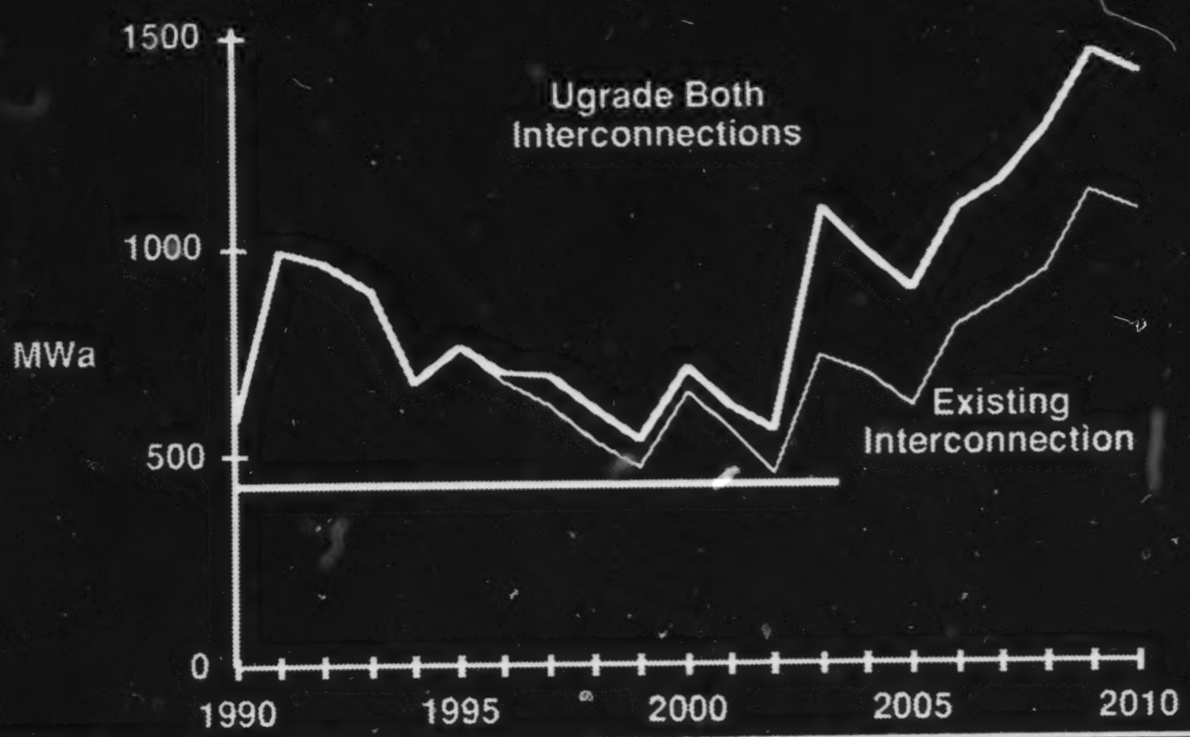
Alberta / British Columbia
Phase 2 Study



Coordinated Operation Benefits

Alberta / British Columbia
Phase 2 Study

Combined System Surplus Energy

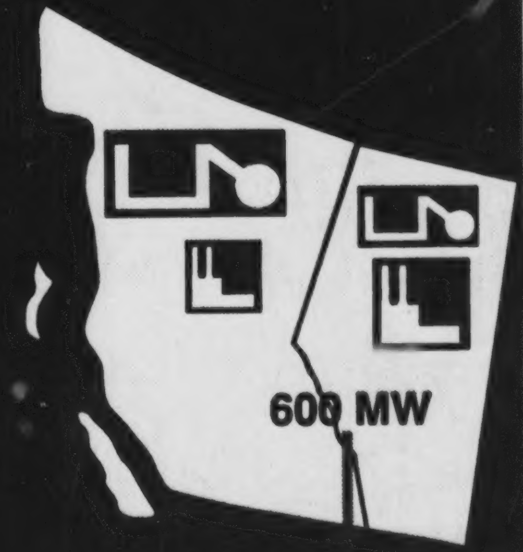


Current Initiatives in Western Canada

Alberta / British Columbia

Phase 2 Study

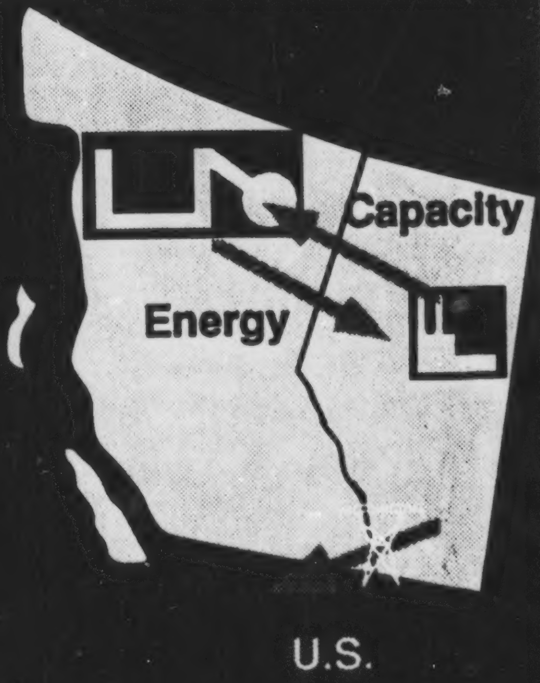
- 600 MW export potential



Current Initiatives in Western Canada

Alberta / British Columbia

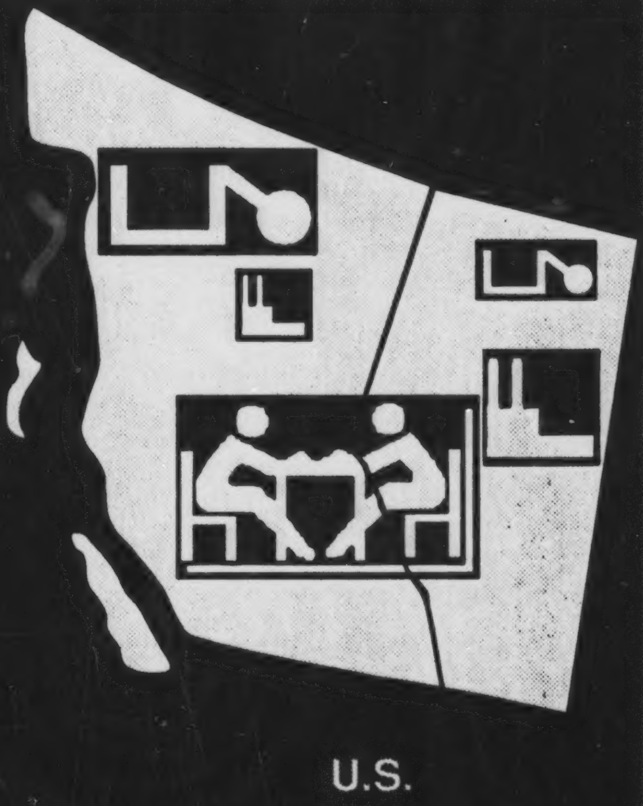
- Letter of understanding
  - Coordinated operation
  - British Columbia firm energy purchase
  - Alberta firm energy purchase
  - U.S. transmission access for Alberta



Current Initiatives in Western Canada

Alberta / British Columbia

- Negotiations in progress
  - Reserve sharing
  - Coordinated operations
  - Alberta capacity purchase
  - British Columbia energy purchase
  - Transmission access



Current Initiatives in Western Canada

Western Electric Utility Cooperation

- Initiated by Western Premiers
- Preliminary study completed, May 1990
  - Background system information
  - Types of potential benefits

Western Electric Utility Cooperation

Next Step

- Manitoba / Saskatchewan Study
  - Similar to the Alberta / British Columbia study
  - Benefits expected to be less

New Coordination Initiatives between Western Systems and External Systems

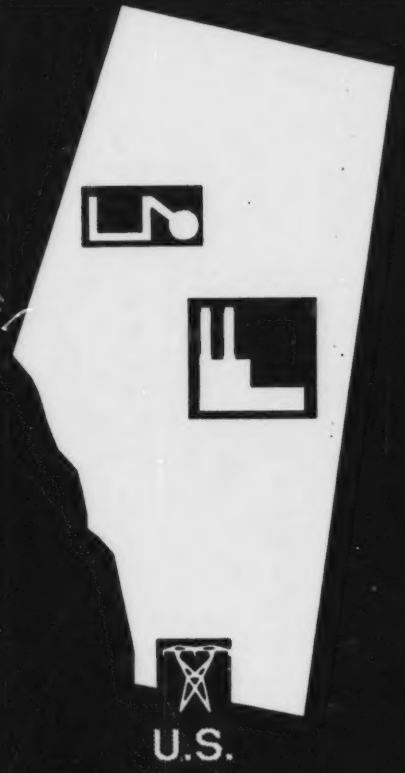
- British Columbia

- Return of Columbia River treaty benefits
- Columbia River Coordination
- Puget Power Interconnection
- Washington Water Power Interconnection

New Coordination Initiatives between Western Systems and External Systems

Alberta

- Montana Interconnection



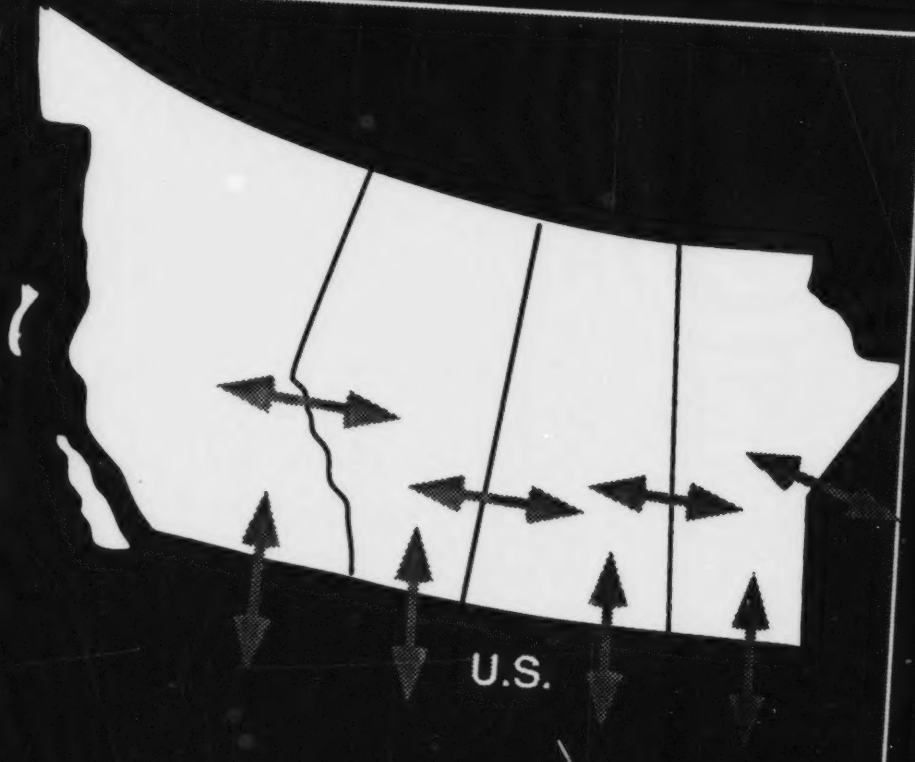
New Coordination Initiatives between Western Systems and External Systems

Manitoba

- Firm Power Sales to Ontario
- Diversity exchanges with U.S.

Summary

Electric Trade Opportunities Exist between Western Provinces and other systems



INTERPROVINCIAL TRADE: THE ONTARIO PERSPECTIVE

Presented by

E. Arthur Marriage
Director of System Planning
Ontario Hydro

"Energy and Electricity: A Conference on
Electric Power Planning in the 1990s",
Montréal, Quebec
June 3-5, 1990

Thank you, Dr. Bruneau, for your introduction. It is a pleasure to be part of such an interesting and topical conference and Panel.

We in Ontario Hydro, who began with a hydro-electric supply can appreciate the value of this gift of nature that our neighbouring provinces continue to enjoy. As a utility which currently derives about three quarters of our energy from fossil and nuclear energy sources, we also appreciate the challenges presented by the use of thermal generation to provide electricity. As the supplier of about 23,000 MW of load which has been growing at about 5% since the 1981/82 recession, we have a good understanding of the main issues which currently face the utility industry in most of North America. Consequently, we are also keenly aware of the benefits and impediments associated with electricity trade among our neighbours.

An important consideration in the overall view of Ontario Hydro's position on electricity interchanges is our policy on building for export: Our current policy is not to build for export unless requested by the provincial government. We build with the objective of meeting our own load and sell only incidental surpluses. These, in turn, result from load variations from forecast and the normal daily, weekly, and seasonal load variations.

However, to appreciate the way we see interprovincial electricity trade in the overall scene requires consideration of several variables, unique to our situation:

(SLIDE 1) The most important of these is geographical in nature. Ontario is a very sprawled-out province -- there are approximately 1700 kilometres, as the bird flies between our eastern boundary with Quebec near Cornwall and our western interconnection with Manitoba near Kenora. The northwestern part of our province, located on the Canadian shield is rich in minerals, forests and other natural assets, but is also rugged and isolated and challenging to construction efforts. The major load and generation areas in the province and its strongest ties with the U.S., are in Southern Ontario, the small area at the bottom of the Province.

(SLIDE 2) Our system can be characterized as strong in the south and weak in the north as illustrated by our interconnecton capabilities shown in this slide. Consequently, major transfers are generally easier to arrange with Michigan and New York than with neighbouring provinces. The U.S. utilities south of us also have major load centres, generation and transmission in reasonable proximity to our Southern Ontario borders. Increased east-west interchanges from Ontario to its neighbouring provinces would require substantial investments in high voltage transmission, especially in the north.

Although Hydro Quebec's major load centre in Montréal is close to the Ontario Hydro system and we have recently augmented our high voltage (500 kV) transmission into the Ottawa area, our transfer capability with Quebec is limited and declining. The long distances between Quebec's generation sources and the Montréal area load centre and the Ontario Hydro system currently results in stability problems if we try to operate the two systems together with synchronous interconnections. The interconnection capability of 1500 MW with Quebec, shown in this slide, consists of generation in the Hydro Quebec system which can be isolated onto the Ontario Hydro system at various locations along the provincial boundary from Montréal up the Ottawa River to the Kirkland Lake area. Load growth in Quebec and isolation of some of the generation in the Montréal area onto the New York system has reduced this capability to about 500 MW. This will continue to decrease in time until major transmission additions are made to this area of the Quebec system. Similar constraints apply to the isolation of Ontario Hydro generation onto the Quebec system.

(SLIDE 3) Of at least equal importance in considering potential interchanges is the cost of power in Ontario and neighbouring areas. This slide demonstrates the major differences between the average electricity retail price to all customers in Canada and the average U.S. price. This slide also shows the much smaller differential between the average electricity price in Ontario and the rest of Canada, especially our neighbours with their hydroelectric systems.

(SLIDE 4) This next slide of monthly residential electric bills is more specific but the message is the same. In most cases, it is more profitable for Canadian utilities to sell power and energy to the U.S. than to adjacent Canadian utilities.

One case in which the price distinction is less clear is Manitoba's alternative U.S. market which has low cost mine-mouth coal generation available. This results in alternative generation costs similar to Ontario with its existing generation mix and its nuclear and fossil options. It is worth noting that Ontario Hydro, and Manitoba Hydro, have negotiated two longer term and many short-term purchases recently, due to Ontario's competitive market position.

The largest and longest of these purchases, concluded last December, was for 1000 MW, beginning in 2000 and extending for about 22 years. It involved some advancements of 1100 km of new transmission in Northern Ontario and the Conawapa Generating Station on the Nelson river in Manitoba. These advancements brought significant benefits to both provinces - the stronger integration of Northwestern Ontario into the provincial grid in Ontario and the early development of a relatively large but economic generating plant for the supply of both Manitoba and Ontario load.

Hydro-Quebec, on the other hand is adjacent to a U.S. market containing mostly fossil fueled generation, remote from coal mines, with a significant portion burning more costly oil and gas. Ontario, to a lesser extent, also has access to the New York and New England markets. In this situation international exchanges make more sense than interprovincial exchanges, at least for major power and energy contracts.

Based on this brief introduction to our system and the neighbouring markets, you can see that we are in a relatively strong position to have exchanges with the U.S., and in a much weaker position to have interprovincial exchanges. However, thanks to our recently negotiated contract with Manitoba, our exchange capability toward the West will be increased to about 1500 MW by the year 2000.

(SLIDE 5) Ontario Hydro's projected energy production for 1993 is shown on this slide. Hydraulic and nuclear generation are used to meet the base load requirements and some peaking. Fossil generation is used to meet the intermediate and peaking requirements.

With Ontario Hydro's energy mix, purchases during on-peak hours with possible sales during off-peak periods, make sense from the viewpoint of energy economics and the requirement to meet acid gas emission limits. The on-peak purchases can displace higher cost fossil generation and new capacity and reduce acid gas emissions. The off-peak sales would be from fossil generation and possibly some nuclear generation surplus to the Ontario requirements and within acid gas emissions.

Because of market economics, most of our sales are to the higher priced U.S. markets and most of our purchases have been from neighbouring Canadian provinces, to the extent purchases have been available.

SLIDE (6) Despite the geographic and economic impediments, Ontario has had a long history of exchanges with its Canadian neighbours, mostly purchases as shown in this slide. The purchases were adversely affected by several years of drought in the recent years which led, last year, to a need to seek purchases in the U.S. The relative system sizes and interconnection capabilities are reflected in the purchase amounts from Quebec and Manitoba.

In addition to the past benefits obtained through purchases of hydroelectric capacity and energy from our neighbouring provinces and the future benefits forecast from the Manitoba purchases discussed earlier, there are some other opportunities for increased interprovincial trade.

(SLIDE 7) We have initiated a study with Hydro-Quebec to consider the viability of improved interconnections. The justifying benefits in this case are unlikely to derive from long term major purchases from Hydro-Quebec; our neighbours recognize the good business logic of selling to the highest bidder -- the international market. However, other synergies between our systems can be exploited to pay for facilities. For example, it is well known that having coal on the ground at a coal-fired generating plant is a major asset in the event that unforeseen events, like an extended drought, preclude the use of other generation; a similar consideration can apply for fuel bundles at nuclear plants, under some conditions. Ontario's nuclear and fossil plants have provided energy assistance to Quebec and Manitoba in the past and could do so in the future if drought conditions result in supply shortages. This of course depends on both availability of Ontario generation and having adequate transmission capability.

A major interconnection capability between Ontario and Quebec can only be exploited if some of Hydro-Quebec's new transmission from James Bay to Montréal can be routed close to the Ontario-Quebec boundary to provide a strong system interconnection point.

One part of the objectives of the study will be to determine whether justification exists for this more favourable routing.

The 1500 MW interconnection with Manitoba and a similar high capacity interconnection with Quebec can provide a number of benefits. They can enhance the option of firm purchases and the sharing of operating synergies between thermal and hydroelectric systems as discussed earlier. They can also improve system reliability in terms of area supply and reserve sharing and they can facilitate the coordination of construction of both generation and transmission in neighbouring provinces.

Coal-by-wire from Western Canada is another concept which may become more attractive given the locations of low sulphur coal deposits and the major load areas in Canada.

Exports are likely to continue over the long term as a control measure for those unforecast events wherein the load fails to grow as expected or short-term load variations provide attractive opportunities for short-term exchanges. Even nuclear energy could be exported on a firm basis, subject to public review and political and regulatory approval; economics would favour such a sale.

It is clear, so far, that there should be ongoing opportunities for electricity transactions, particularly with Western Canada and the U.S., although there appear to be increasing possibilities for exchanges with Quebec.

It is also clear that federal and provincial co-operation and support is very important, if not essential, if the current level of interprovincial exchanges is to be increased. Lines which extend over hundreds of kilometers, especially those involving more than one province, demand high levels of cooperation and support from political and regulatory jurisdictions. Government support for routing approvals of major interprovincial transmission is an important ingredient; otherwise the disincentives can be so great as to be almost prohibitive. Similarly financial incentives, if they are to be practical, must be managed and made available within practical time frames. Opportunities to execute beneficial exchanges tend to be fleeting events; failure to be able to respond quickly, either by use of existing facilities or by expeditious installation of new facilities, can result in foregone benefits. Our experience has shown that all of our interconnections have always provided much greater benefits than were foreseen at the time of their commitment.

In closing, I would like to quickly summarize Ontario Hydro's views on the impediments and opportunities associated with interprovincial electricity trade.

(SLIDE 8) The impediments to increased interprovincial electricity transfers, especially in northern Ontario, include the long geographic distances to major load centres, the difficult topography represented by the Canadian shield and the limited existing transmission network in the northern part of Ontario. In addition to the need for long and expensive transmission facilities, there are only small differentials between the costs of producing electricity in Manitoba, Ontario and Quebec. In contrast, there are shorter distances and greater economic differentials for electricity transfers to the neighbouring U.S. states south of these Canadian provinces.

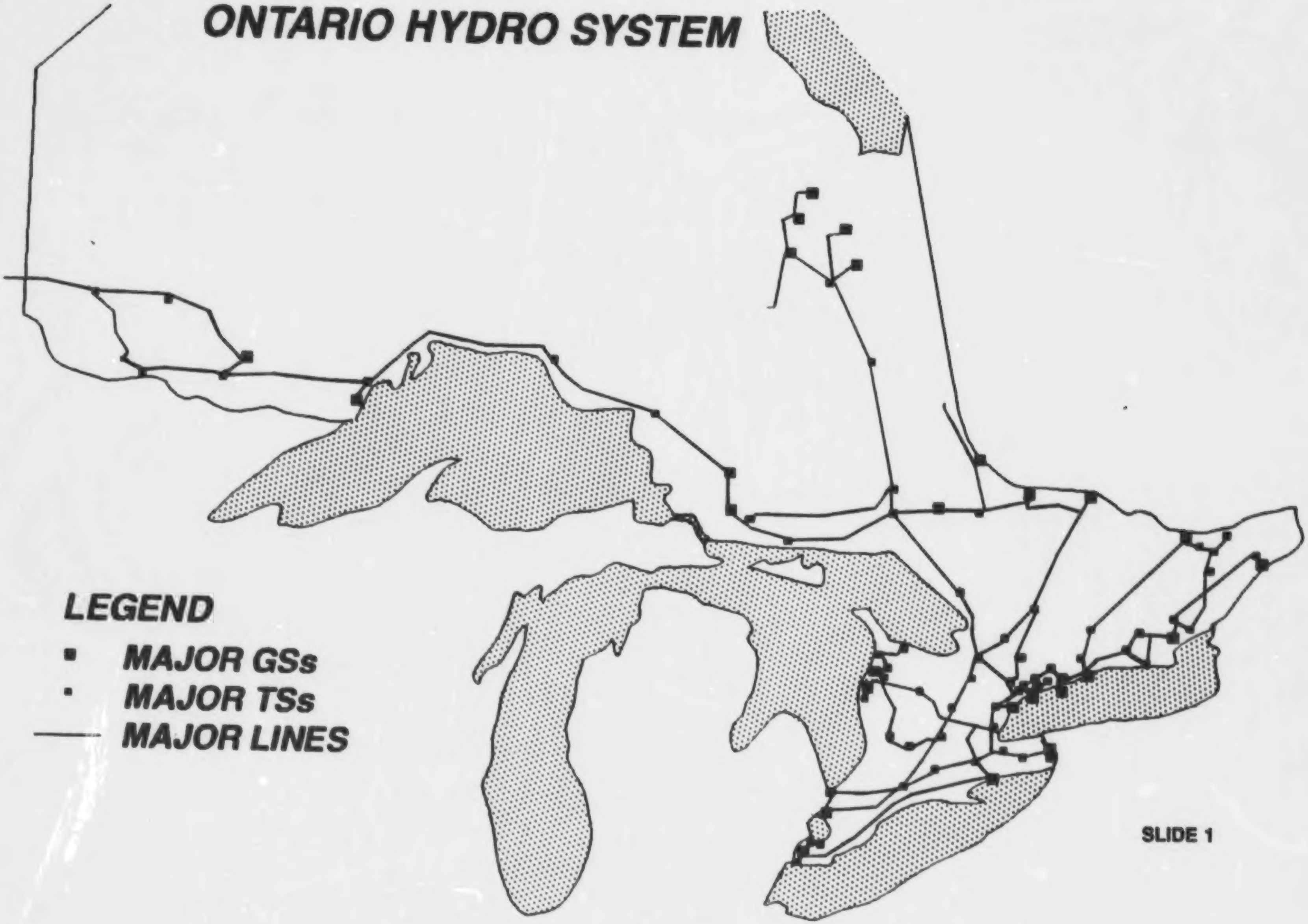
Although there are economic impediments to interprovincial electricity transfers there are still opportunities to increase these transfer capabilities, as illustrated by the 1000 MW purchase by Ontario from Manitoba for 22 years scheduled to begin in the year 2000. These opportunities include:

(a) the possible advancement of hydroelectric generation by "have" provinces for sale to the "have-not" provinces;

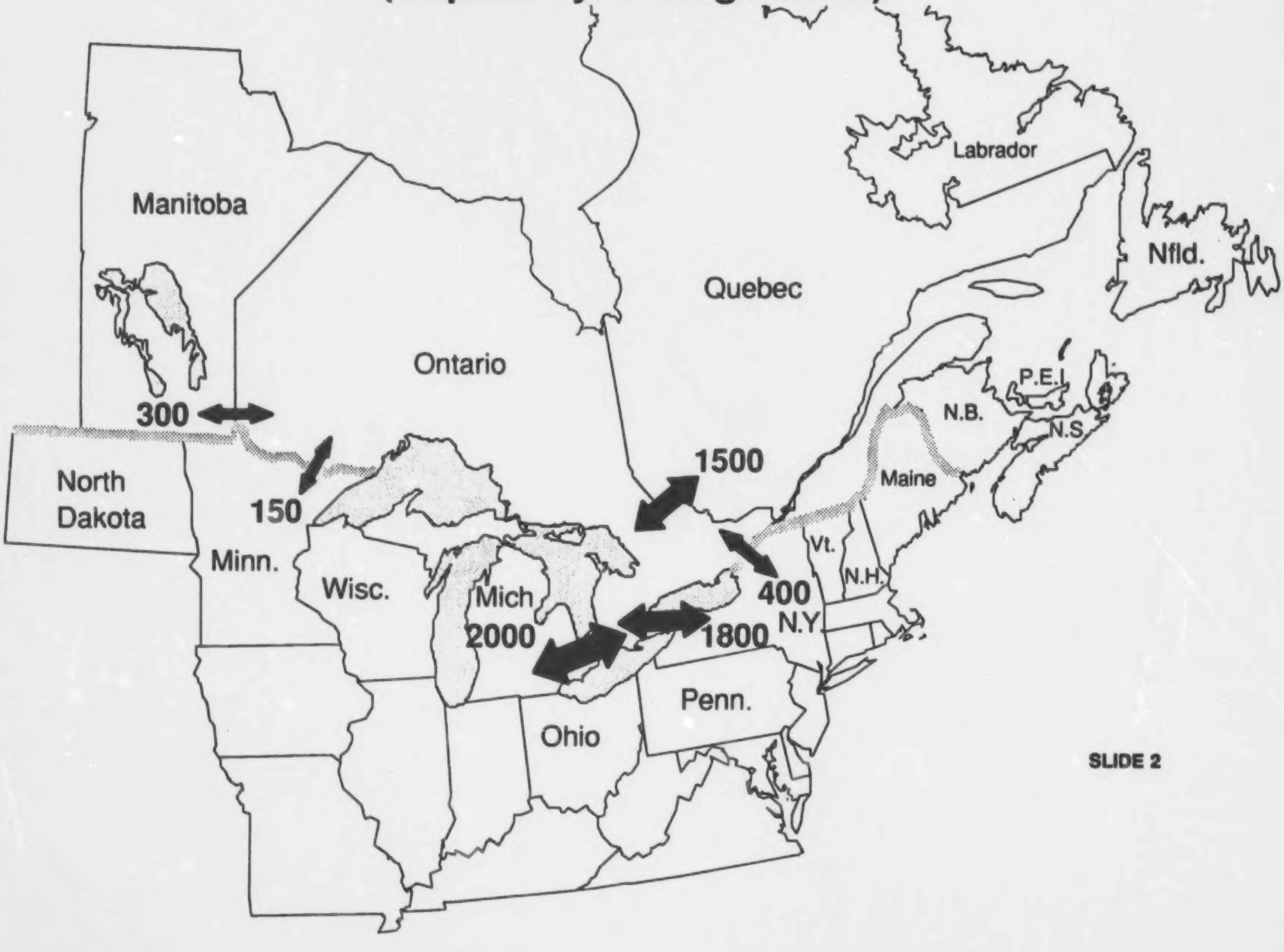
(b) the possible export of thermal generation, especially nuclear energy, to augment provinces dependent on hydroelectric generation, especially during drought conditions; and

(c) the improved operating flexibility, improved system reliability, and reduced operating costs achieved through coordinated system development and generation dispatching, if strong interconnections are in place.

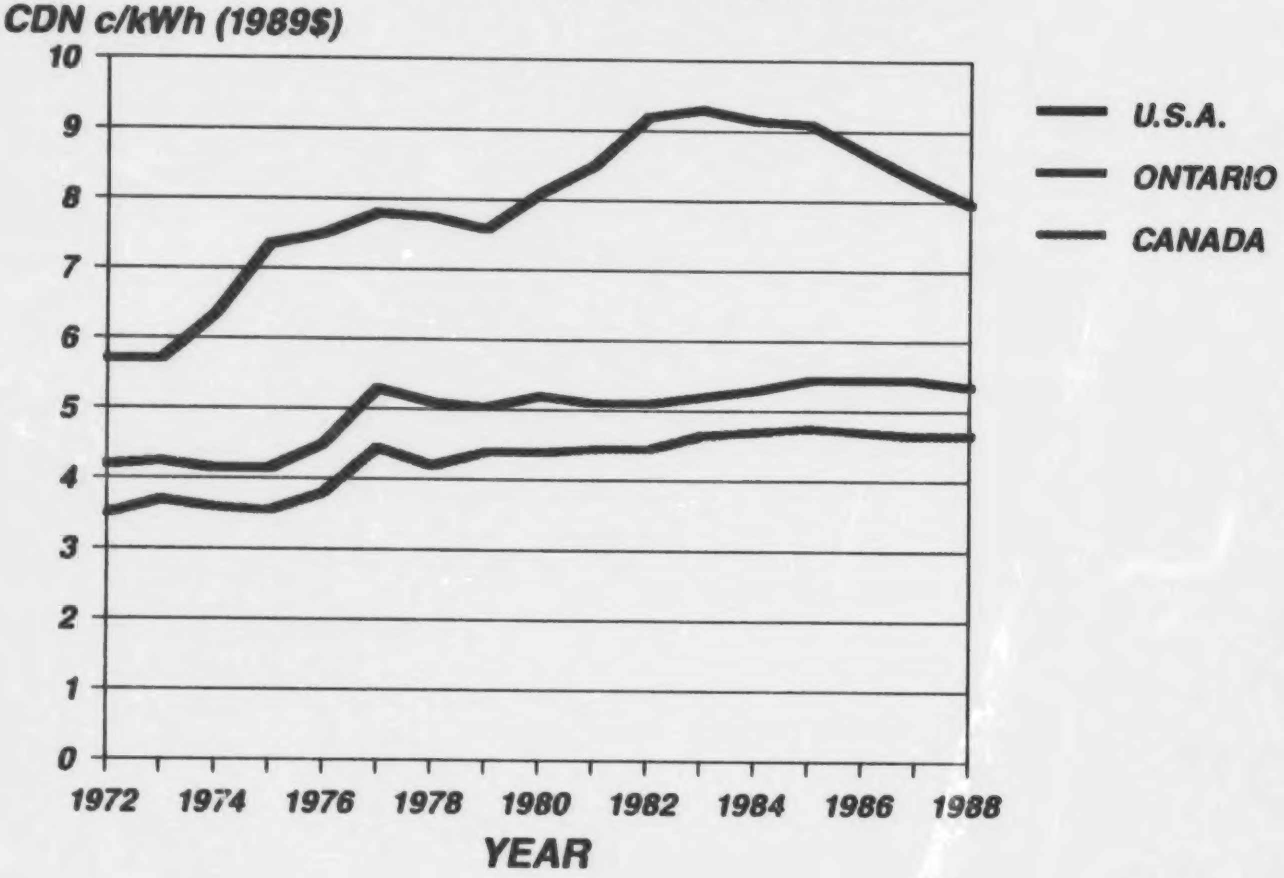
ONTARIO HYDRO SYSTEM


LEGEND
■ MAJOR GSs
▪ MAJOR TSs
— MAJOR LINES

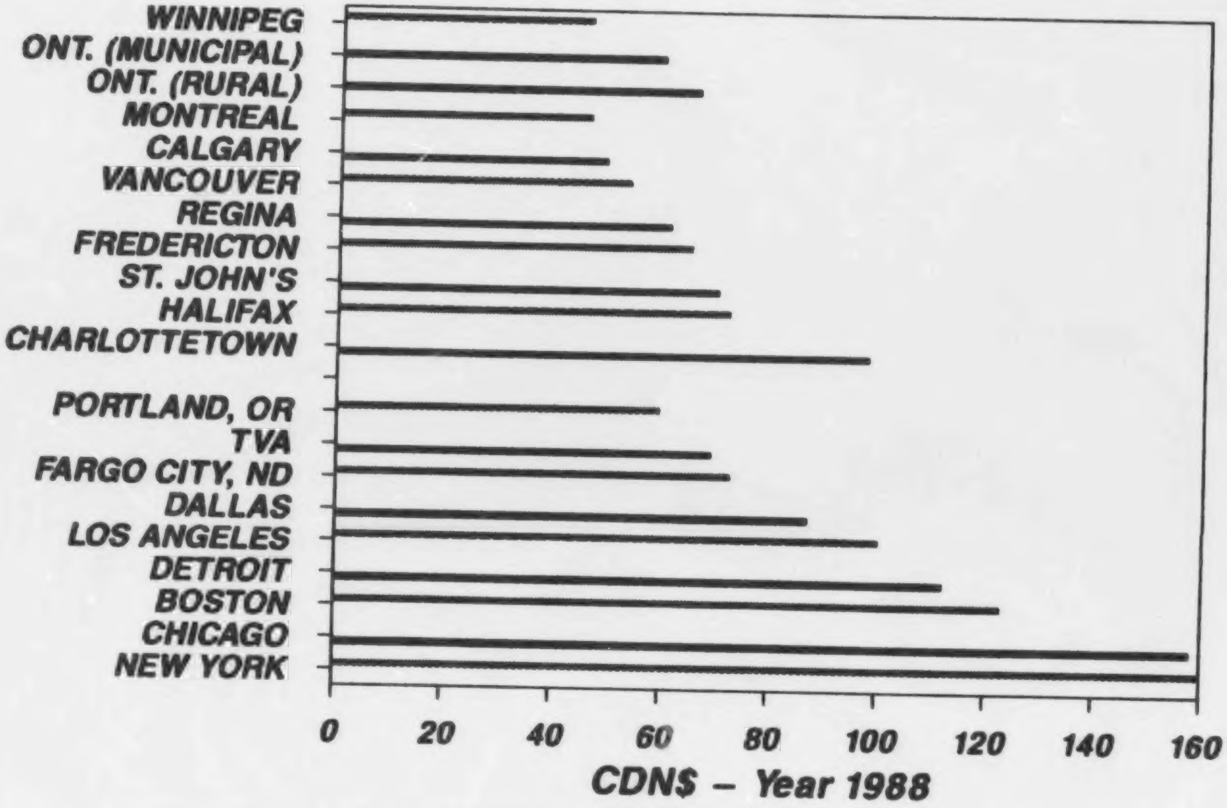
Ontario Hydro Interconnections
(Capability in Megawatts)


Manitoba
Ontario
Quebec
Labrador
Nfld.
P.E.I.
N.B.
N.S.
Maine
Vt.
N.H.
N.Y.
Penn.
Ohio
Mich
Wisc.
Minn.
North Dakota
300
150
2000
1800
1500
400

AVERAGE ELECTRICITY RETAIL PRICE TO ALL CUSTOMERS



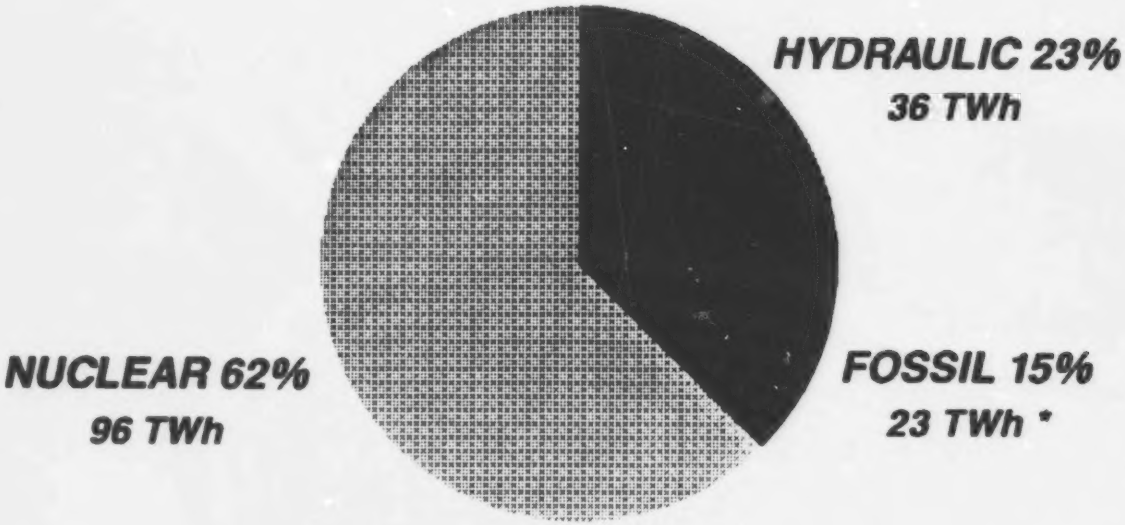
MONTHLY RESIDENTIAL ELECTRIC BILLS
PER 1000 kWh *



* EXCLUDING SALES TAX & SPECIAL LOCAL CHARGES

1993 PROJECTED ANNUAL ENERGY PRODUCTION BY GENERATION TYPE

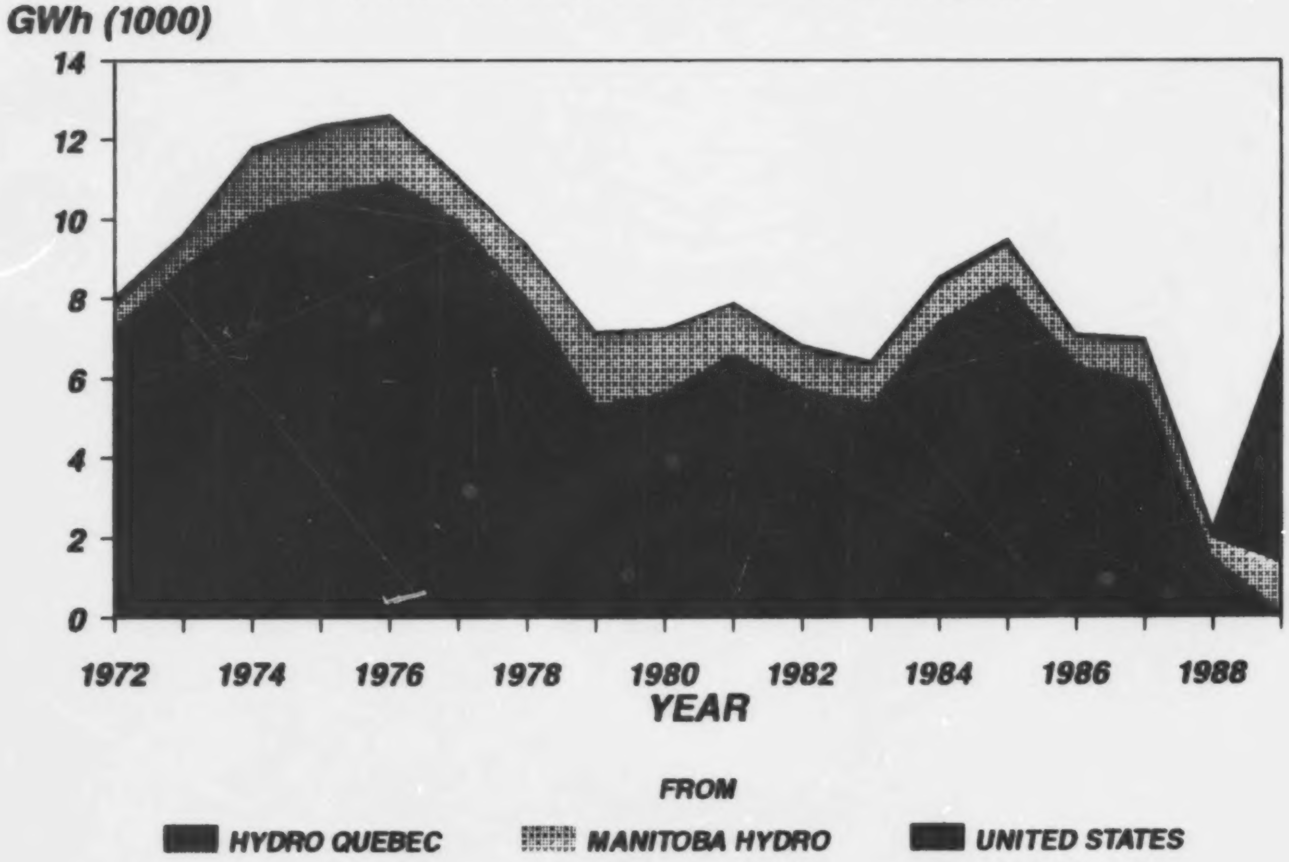
155 TWh



ENERGY

* COAL 22.9 TWh + OIL 0.1 TWh

ONTARIO HYDRO PURCHASES



OPPORTUNITIES FOR INTERPROVINCIAL TRADE IN ELECTRICITY

- QUEBEC INTERCONNECTION
- FIRM PURCHASES
- THERMAL/HYDRAULIC SYNERGIES
- RELIABILITY IMPROVEMENTS
    - AREA SUPPLY
    - RESERVE SHARING
- CO-ORDINATED CONSTRUCTION
- FUEL BY WIRE
- FIRM NUCLEAR EXPORTS

SUMMARY

IMPEDIMENTS TO INTERPROVINCIAL ELECTRICITY TRADE

- LONG GEOGRAPHICAL DISTANCES
- DIFFICULT TOPOGRAPHY
- LIMITED TRANSMISSION
- SMALL ECONOMIC DIFFERENTIALS

OPPORTUNITIES FOR INTERPROVINCIAL TRADE

- ADVANCEMENT OF HYDRO-ELECTRIC GENERATION
- EXPORTS OF THERMAL ENERGY TO HYDRO-ELECTRIC DEPENDENT SYSTEMS
- IMPROVED OPERATING FLEXIBILITY, SYSTEM RELIABILITY & REDUCED OPERATING COSTS

INTERPROVINCIAL AND INTERNATIONAL TRADE: A PERSPECTIVE FROM ATLANTIC CANADA

Presented by

Terrence S. Thompson
Director, Long Term Export Marketing
& Nuclear Affairs
New Brunswick Power
Fredericton, New Brunswick

ENERGY AND ELECTRICITY: A CONFERENCE ON
ELECTRIC POWER PLANNING IN THE 1990's
Montréal, Québec
June 3-5, 1990

INTRODUCTION

Interprovincial and international trade of electricity is an integral and essential element in New Brunswick's energy policy.

(Slide 1) The strategy of electrically interconnecting with neighbouring utilities began more than 30 years ago with a line connecting a small part of Northern Maine to New Brunswick. The timing coincided with the completion of the Beechwood hydro plant. A few years later, in 1960, the first of several electrical ties with Nova Scotia was completed. The first major interconnection with New England went into operation in 1970. In 1972, the world's first solid state High Voltage Direct Current (HVDC) converter station went into service at Eel River in northern New Brunswick connecting New Brunswick and Québec in a major way and giving NB Power the opportunity to buy hydro power from Churchill Falls which was surplus to Hydro Québec's needs. A second HVDC converter station went into service in 1985 at

Madawaska, Québec doubling the interconnection capacity with Québec. In 1977, a submarine cable was installed between New Brunswick and Prince Edward Island, completing electrical ties with every neighbouring utility.

(Slide 2) Today, New Brunswick, with interconnections totalling over 2,300 MW - Québec (1,000 MW), New England (800 MW), Nova Scotia (400 MW) and PEI (100 MW) is the most heavily interconnected province relative to its size in Canada. Interconnection capacity is comparable to in-province peak demand of 2500 MW.

(Slide 3) In fiscal year 1989/90, NB Power purchased 3600 gWh of energy valued at $101 million and sold 7200 gWh valued at $312.7 million. Virtually all the purchases were from Québec. In turn, NB Power had sales to Québec valued at $95.3 million, sales to other Canadian provinces of $26.5 million and sales to New England of $190.9 million.

BENEFITS OF INTERPROVINCIAL AND INTERNATIONAL TRADE

Electrical interconnections with neighbouring utilities began as a means of mutual assistance during emergencies but soon became major economic links. They led to improvements in operating efficiency by allowing for the sharing of reserves and hence a reduction in the amount of standby capacity required on each system and hence lower costs. This was followed by exchanges of economy energy on an interruptible basis further lowering operating costs.

Interconnections provide more leeway on the installation of new generating equipment on an economical basis as to timing, location and size of the units. New Brunswick is able to develop larger-sized units than otherwise possible with attendant economies of scale and is able to buy and sell surplus energy as the opportunity or need arises.

International interconnection transactions are licensed by the National Energy Board and are conducted in a manner such that each utility optimizes the benefits to its customers while ensuring that environmental standards are met and the public interest is respected.

(Slide 4) Firm and interruptible purchases and sales across interconnections benefit both parties and, in the case of New Brunswick, the benefits of interconnection transactions in terms of in-province rate relief have averaged 13.1% over the past 10 years.

MAJOR INTERPROVINCIAL AND INTERNATIONAL SALES AND PURCHASES

(Slide 5) Major sales and purchases with neighbouring utilities undertaken, underway or planned since the early 70's are outlined below.

400 MW System Sale

As mentioned, New Brunswick completed its major interconnection with New England in 1970. At that time New Brunswick combined surplus hydro capacity from its Mactaquac development, the purchase of Churchill Falls power from Hydro Québec through the Eel River tie with purchased coal power from Nova Scotia and sold a 400 MW system sale to New England for 5 years.

400 MW Coleson Cove Unit Participation Sale

In 1976, NB Power entered into a 10-year unit participation sale for about 40% of the 1,000 MW oil-fired Coleson Cove Generating Station. This was the first unit participation sale from Canada to the United States.

20 MW Dalhousie Ownership

In 1981 NB Power sold Maritime Electric of Prince Edward Island a 10% ownership of the Dalhousie 2 coal-fired plant. This was the first joint ownership agreement between Canadian utilities in a major generating facility.

230 MW Point Lepreau Unit Participation Sale

In 1983, upon completion of the 630 MW nuclear unit at Point Lepreau, four New England utilities entered into unit participation sales for 230 MW of output. This was the first sale of nuclear power to the United States from Canada. The unit has the second best lifetime performance for nuclear plants in the world to the end of 1989 and is an economic source of supply for New Brunswick and New England. All four New England utilities have taken up their three one-year contract extension options until October 31, 1991.

350 MW Hydro Québec Purchase

In 1988, New Brunswick entered into a 6 1/2 year firm capacity and energy purchase from Québec. The purchase option allows for the timely addition of 450 MW coal-fired units at Belledune which will replace the Hydro-Québec contract in 1994.

50 MW PEI Sale

In addition to purchasing up to 300 MW of capacity and energy for its own needs from Hydro Québec between 1988 and 1994, NB Power also contracted for up to a further 50 MW and, in turn, contracted for sales up to this quantity to Prince Edward Island.

400 MW Hydro-Québec Peaking Power Sale

Early in 1990 an opportunity arose to supply Québec with long-term peaking power. An agreement for a 20-year sale has been signed calling for NB Power to supply 400 MW of peaking capacity (400 MW to 1998, 300 MW to 2002 and 200 MW to 2011). This sale has a projected revenue of $900 million. NB Power is installing 400 MW of combustion turbines to meet the requirements of this contract and to help meet provincial peak loads by phasing the units back into NB Power's system to meet projected needs.

200 MW Lepreau Extension Sale

It is in New Brunswick's interest to continue to sell about 200 MW of Lepreau to New England to keep the unit size on the NB Power system to an optimum 400 MW. An existing participant, Massachusetts Municipal Wholesale Electric Company

(MMWEC) accepted a further extension to 1994 of their 100 MW contract (drops to 50 MW in final year) and a further 100 MW is being marketed in New England. The MMWEC contract is currently before the National Energy Board for approval.

600 MW Package

For the longer term, NB Power is offering a package of capacity and energy consisting of 200 MW from Point Lepreau and 200 MW from each of two units at Belledune. The 600 MW package would commence November 1, 1994 and be sold for a 10-20 year period. The sale would assure long-term benefits to New Brunswickers comparable to benefits from all forms of export activity today.

The price is based on the average cost of the two coal-fired units at Belledune and would include a markup to cover financial risk, administration and profit. The package would provide a revenue of $9 billion over 20 years.

REGULATION OF INTERPROVINCIAL AND INTERNATIONAL TRADE

New Brunswick's geographical location is one of very few natural advantages that assist the province in providing economic electrical energy supply.

(Slide 6) NB Power has promoted and fostered interprovincial and international trade. The utility has been innovative in its business concepts and electricity consumers in New Brunswick have benefited jointly with consumers in neighbouring jurisdictions.

Interprovincial Trade

In principle, NB Power supports the objectives of expanded interprovincial trade and reduced barriers to transmission access. However we believe that these matters should be left to the provinces to deal with on a negotiated business basis and that transmission access should not be legislated. This was also the conclusion of a recent report by E.L. Fytche, a retired NEB employee to the CEA Interconnection Committee. Fytche concluded "it is the author's view that legislated access for wheeling would consume vast quantities of management and technical competence in hearing and court actions (as indeed it does in the U.S.), with the possibility of marginal gains in economic efficiency when compared with the progress that can be made through negotiated co-operative action". The role of the Federal Government should be to encourage interprovincial co-operation through appropriate financial support, i.e. support for the economic choice.

NB Power is willing to enter into contractual arrangements for the provision of wheeling services, provided there is no adverse effect on domestic New Brunswick customers and there are not lost opportunity benefits to NB Power.

Evidence of this policy are the agreements between NB Power and Maine Public Service and Eastern Maine Electric Cooperative, whereby entitlement to units in Southern Maine, specifically Maine Yankee and Wyman are wheeled through the NB Power system. This enables these two utilities, which are not directly interconnected with the MEPCO 345 kV line, to purchase from native U.S. generating stations. The agreement with Maine Public Service also provides for the wheeling of wood-fired generation from northern to southern Maine.

For interprovincial Canadian transactions, NB Power has acted more as a broker in that we have purchased the capacity and/or energy from one utility and subsequently sold it to another. We believe this type of transaction to be more straight forward and to offer more benefits to all parties than wheeling, particularly in the Canadian context where generally utilities are Crown Corporations with province-wide jurisdiction and distances are great.

There are several benefits to the brokering approach. First, the broker's markup can be less than an applicable wheeling rate, which is a saving to the purchaser. Second, the purchaser negotiates with the utility which is directly connected with it, allowing the purchaser to include factors in negotiations that would otherwise not be possible. Third, because the broker has first option on what is being sold he is better able to ensure that domestic customers are not adversely impacted as compared to a flow-through wheeling arrangement.

International Trade

NB Power supports the National Energy Board's move to deregulate exports and doesn't see any reason why our 600 MW package, for instance, could not be Permitted.

The objective of Amendments to the NEB Act, known as Bill C-23, which have recently been passed by the Government of Canada is to implement a system for regulating electricity exports that streamlines the process and minimizes overlap with provincial regulation. The approval process in terms of time required may be shortened by many months. The NEB now has the discretion to issue a permit if the application satisfies the export criteria regarding fair market access, extra-provincial effects, and environmental impacts thereby eliminating the time-consuming and costly hearing process. It is intended that the NEB regulation would complement and not duplicate Provincial regulation.

We do have a concern as to what is meant by "having regard to all considerations that appear to be relevant, including the impact of the exportation on the environment" in relation to whether an application is bumped-up to a licence hearing. The way Bill C-23 reads is too vague. We really don't know what we are subject to - regulations, standards, or guidelines? Federal or Provincial? We believe the "environmental requirement" used as a basis for designation, or non-designations should be Provincial, rather than Federal, as this would conform with the non-duplication objectives of the regulatory process.

We have asked that the NEB hold a generic hearing on the environmental aspects of exports so that exporting Canadian utilities can understand the "rules of the game" so to speak, and the NEB have indicated they will consider such a hearing.

The emergence of the concept of 'externalities' by U.S. regulators is also of concern to Canadian exporters. NB Power strongly endorses the principle of full consideration of all environmental factors. However, we believe that the strict standards in New Brunswick/Canada are established to meet the unique conditions and opportunities of our environment. To penalize a project for not meeting conditions specific to a particular state could result in substantially reduced options for fuel diversity.

The emerging least cost planning and competitive bidding processes in various states are of concern to Canadian exporters. Utilities may be reluctant to negotiate contracts outside the bidding process in the midst of evolving regulations, and the rules are likely to significantly limit the opportunities for negotiating long term power sales agreements outside of an all-resource bidding framework. And, if a contract is negotiated, the price may become the "reference price" which independent power producers and other non-utility generators use in establishing their bid in the competitive process.

And these processes vary from State to State. In marketing a large quantity of power to several states, Canadian exporters have to deal with a large number of regulatory bodies at all levels of government - federal, state and municipal. A more streamlined approach is certainly something we would like to see.

As Roland Priddle, Chairman of the National Energy Board, said in a recent speech in Boston "if pursued too aggressively by PUC's, least-cost planning and competitive bidding processes could result in the loss of some secure, long-term environmentally-friendly and competitively-priced energy supplies for the New England economy".

FUTURE OPPORTUNITIES FOR INTERPROVINCIAL AND INTERNATIONAL TRADE

(Slide 7) The proposed 600 MW sale can be undertaken within the transmission capability of the existing 345 kV line into the New England area. NB Power is also working at a three-stage increase in its transmission transfer capability into New England.

1) The first stage would be a second 345 kV line as far as Bangor to increase transfer capability from 700 MW to 1000 MW.

2) The second stage, involving additional 345 kV transmission south of Bangor bringing the tie capacity up to 1200-1400 MW, would enable NB Power to consider transfer of up to 600 MW from Québec or Nova Scotia.

3) Finally, a third 345 kV circuit, bringing the total transfer capability to 1800-2000 MW, would allow additional power into New England either from generating facilities in New Brunswick or as transfers of power from Québec or Nova Scotia.

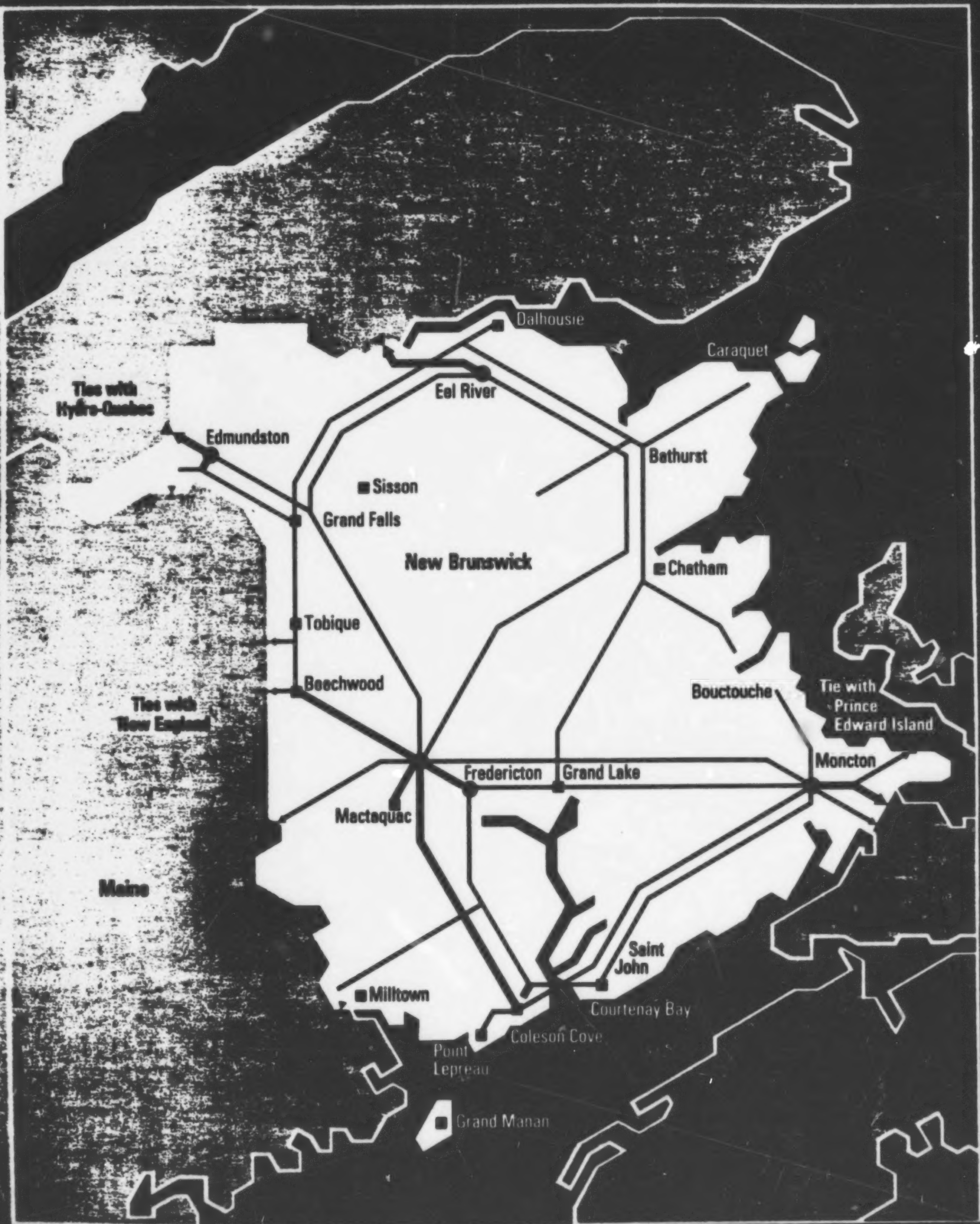
CONCLUSION

Interprovincial and international trade of electricity in Atlantic Canada provides a considerable measure of economic efficiency for regional consumers.

NB Power supports the move to deregulate international trade and encourages regulators to standardize regulations and streamline the approval process.

NB Power believes transmission access should be negotiated not legislated for interprovincial trade. The first obligation of any provincial utility is to its domestic customers. Through brokering-type arrangements these interests can be protected and benefits accrued through negotiated business arrangements for international and interprovincial trade.

NB Power's 600 MW Package is the latest in a successful series of interprovincial and international sales and purchases. For this and other potential future opportunities to come to fruition will require the common support of utilities and regulators at all levels.


Dalhousie
Caraquet
Eel River
Ties with Hydro-Quebec
Edmundston
Bathurst
Sisson
Grand Falls
New Brunswick
Chatham
Tobique
Beechwood
Ties with New England
Bouctouche
Tie with Prince Edward Island
Moncton
Fredericton
Grand Lake
Mactaquac
Maine
Saint John
Milltown
Courtenay Bay
Coleson Cove
Point Lepreau
Grand Manan

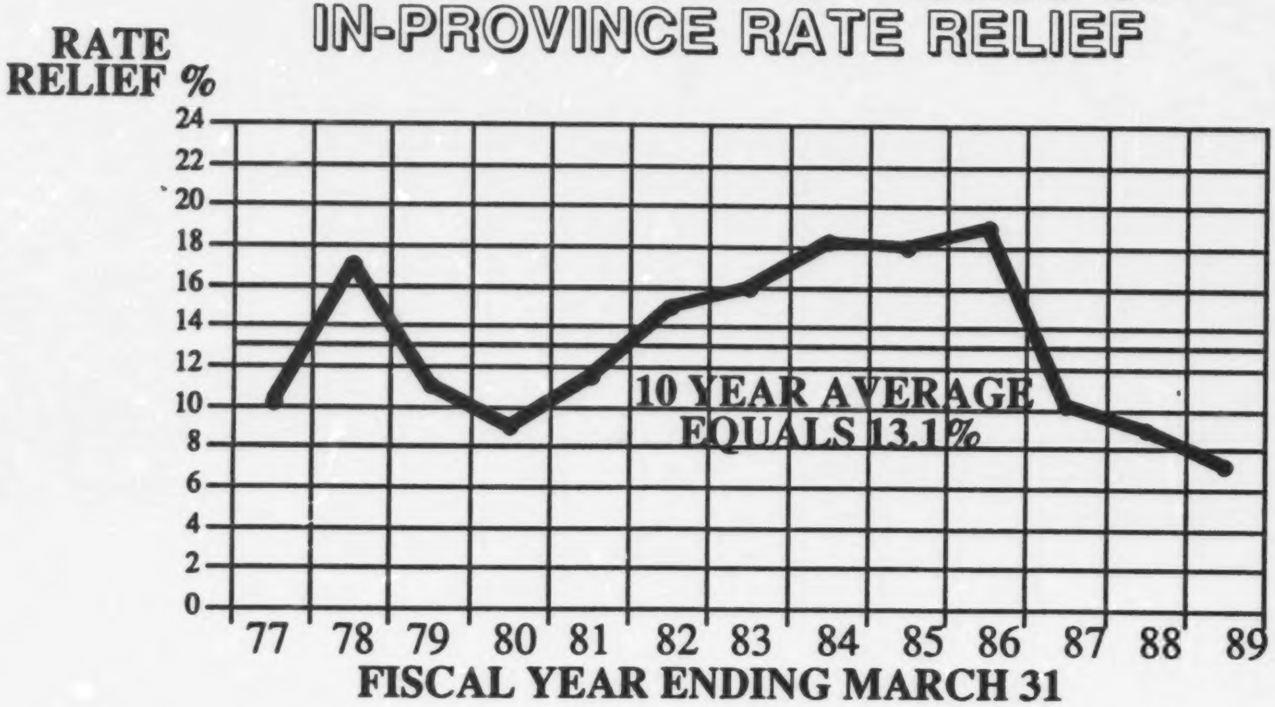
- Interconnections totalling over 2300 MW

• Quebec	1,000
• New England	800
• Nova Scotia	400
• P.E.I.	100

NB POWER 1989/1990 INTERPROVINCIAL AND INTERNATIONAL TRADE

	$ Millions	
Purchases	101.0	(Mostly Quebec)
Sales	95.3	(Quebec)
	26.5	(other Provinces)
	190.9	(U.S.)
	312.7	Total

BENEFITS OF INTERCONNECTION TRANSACTIONS IN TERMS OF IN-PROVINCE RATE RELIEF



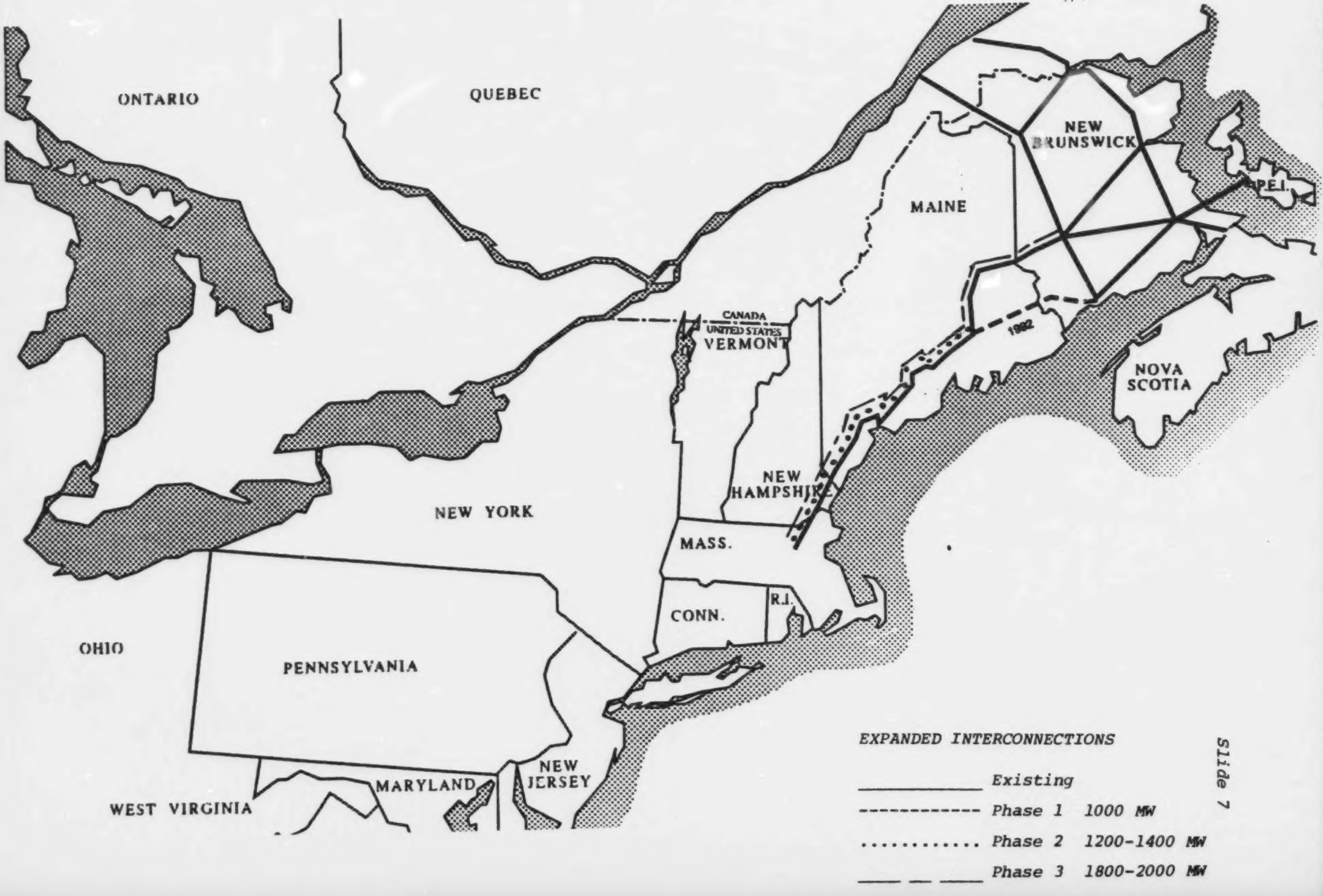
10 YEAR AVERAGE EQUALS 13.1%

MAJOR INTERPROVINCIAL & INTERNATIONAL SALES & PURCHASES

400 MW	System Sale
400 MW	Coleson Cove Sale
20 MW	Dalhousie Ownership
230 MW	Point Lepreau Sale
350 MW	Hydro Quebec Purchase
50 MW	P.E.I. Sale
400 MW	Hydro Quebec Sale
200 MW	Lepreau Extension Sale
600 MW	Package

REGULATION

- Interprovincial
- International


ONTARIO
QUEBEC
NEW BRUNSWICK
P.E.I.
MAINE
CANADA
UNITED STATES
VERMONT
1982
NOVA SCOTIA
NEW HAMPSHIRE
NEW YORK
MASS.
CONN.
R.I.
OHIO
PENNSYLVANIA
NEW JERSEY
MARYLAND
WEST VIRGINIA
EXPANDED INTERCONNECTIONS
Existing
Phase 1 1000 MW
Phase 2 1200-1400 MW
Phase 3 1800-2000 MW

U.S. Demand for Canadian Electricity

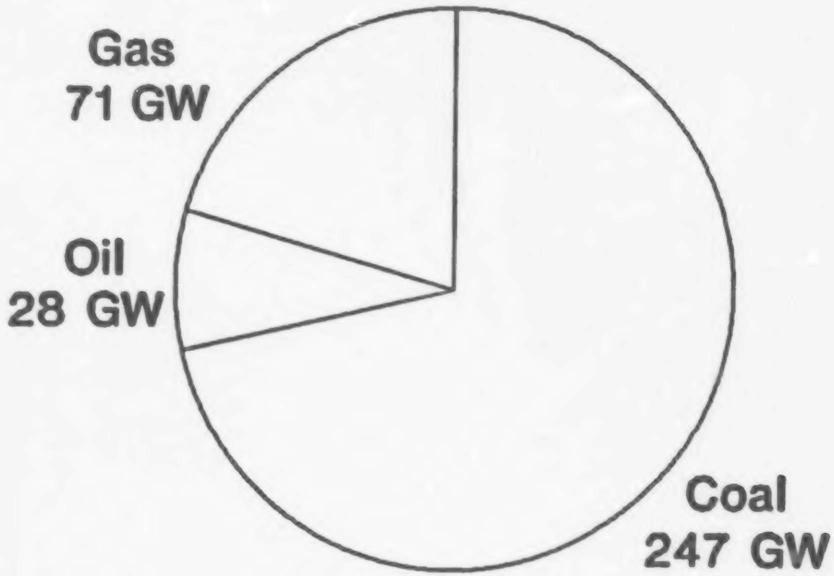
Presented by
Robert T. Eynon
U.S. Department of Energy

to
Energy and Electricity
A Conference on Electric Power Planning
in the 1990's

Montreal, Quebec
June 4, 1990

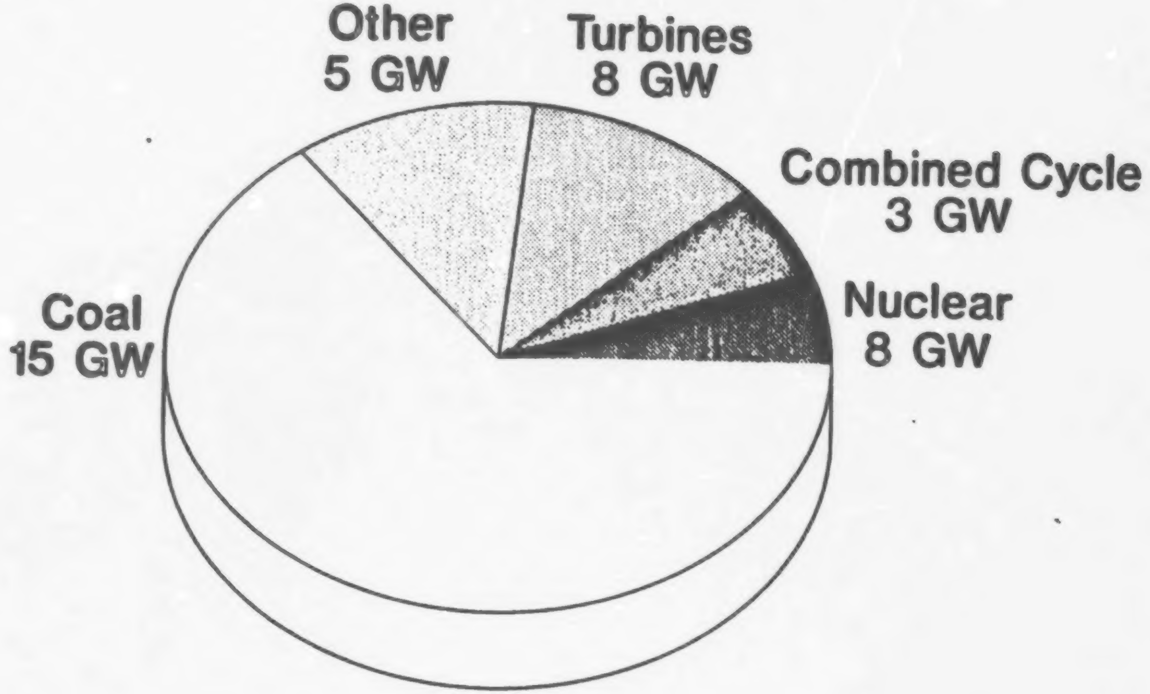
Life Extension Assumed, 1990 - 2010

(346 Gigawatts)

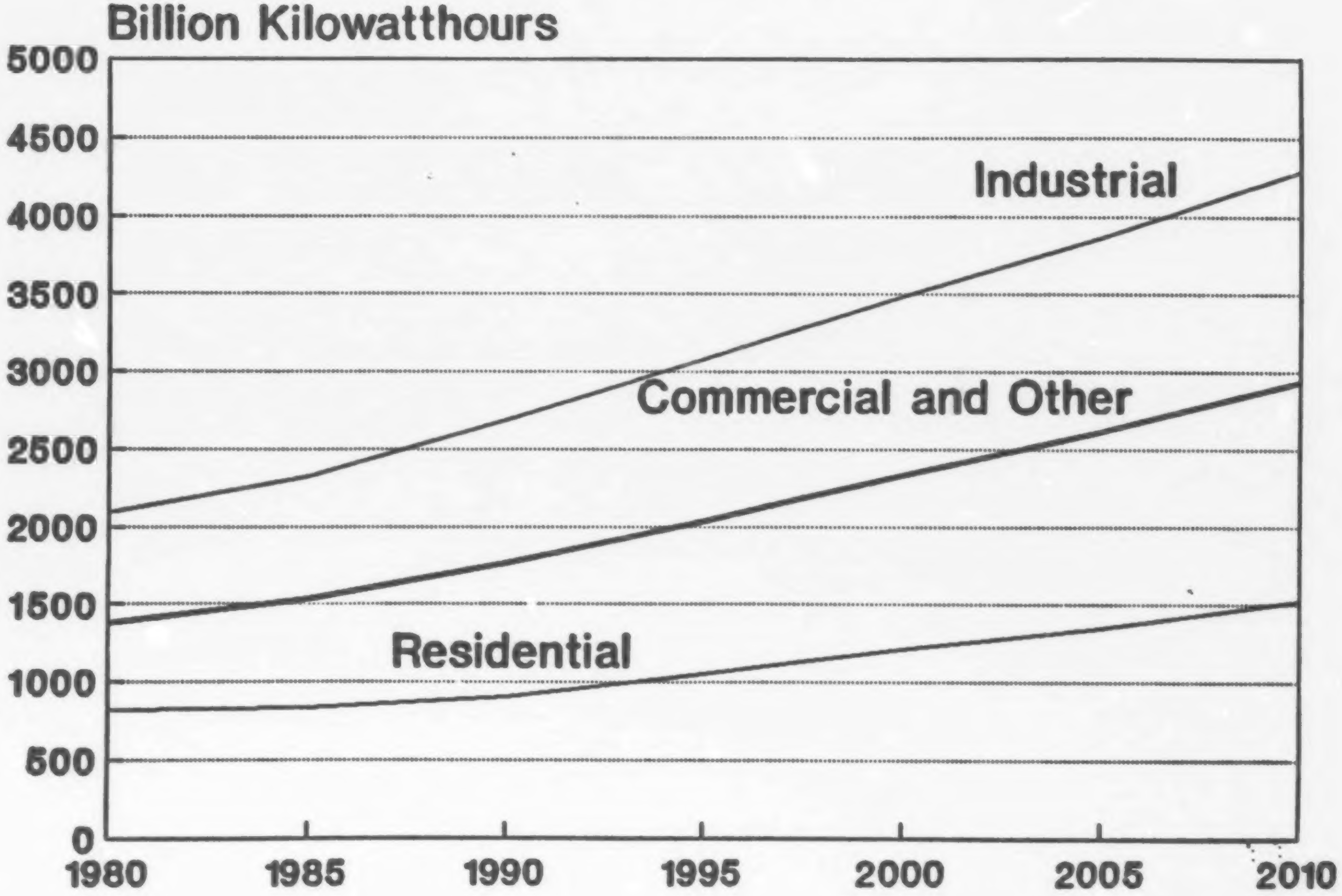


Source: Annual Energy Outlook, 1990

Planned Utility Construction, 1990-2010
(39 Gigawatts)

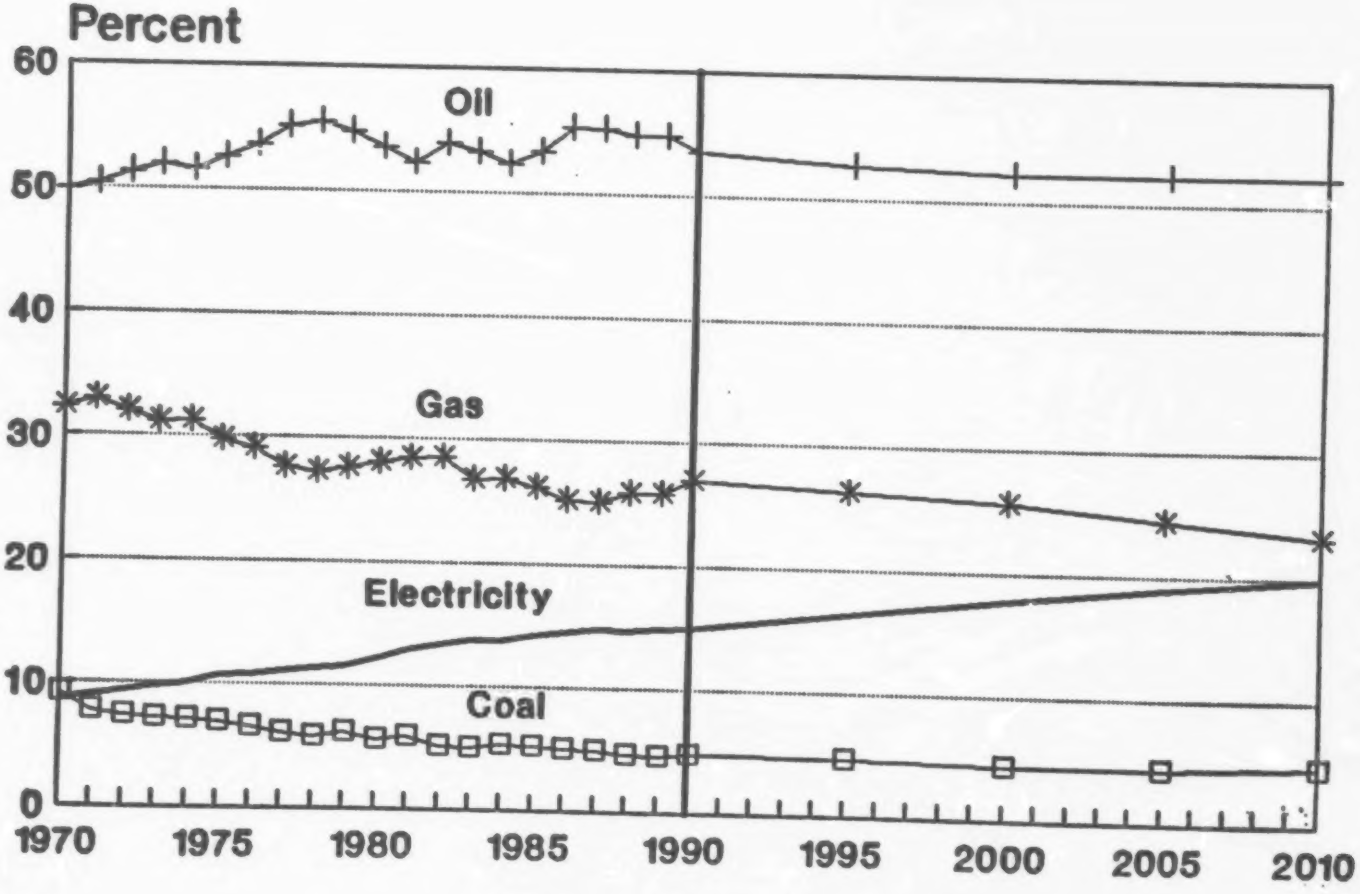


Electricity Sales, 1985-2010

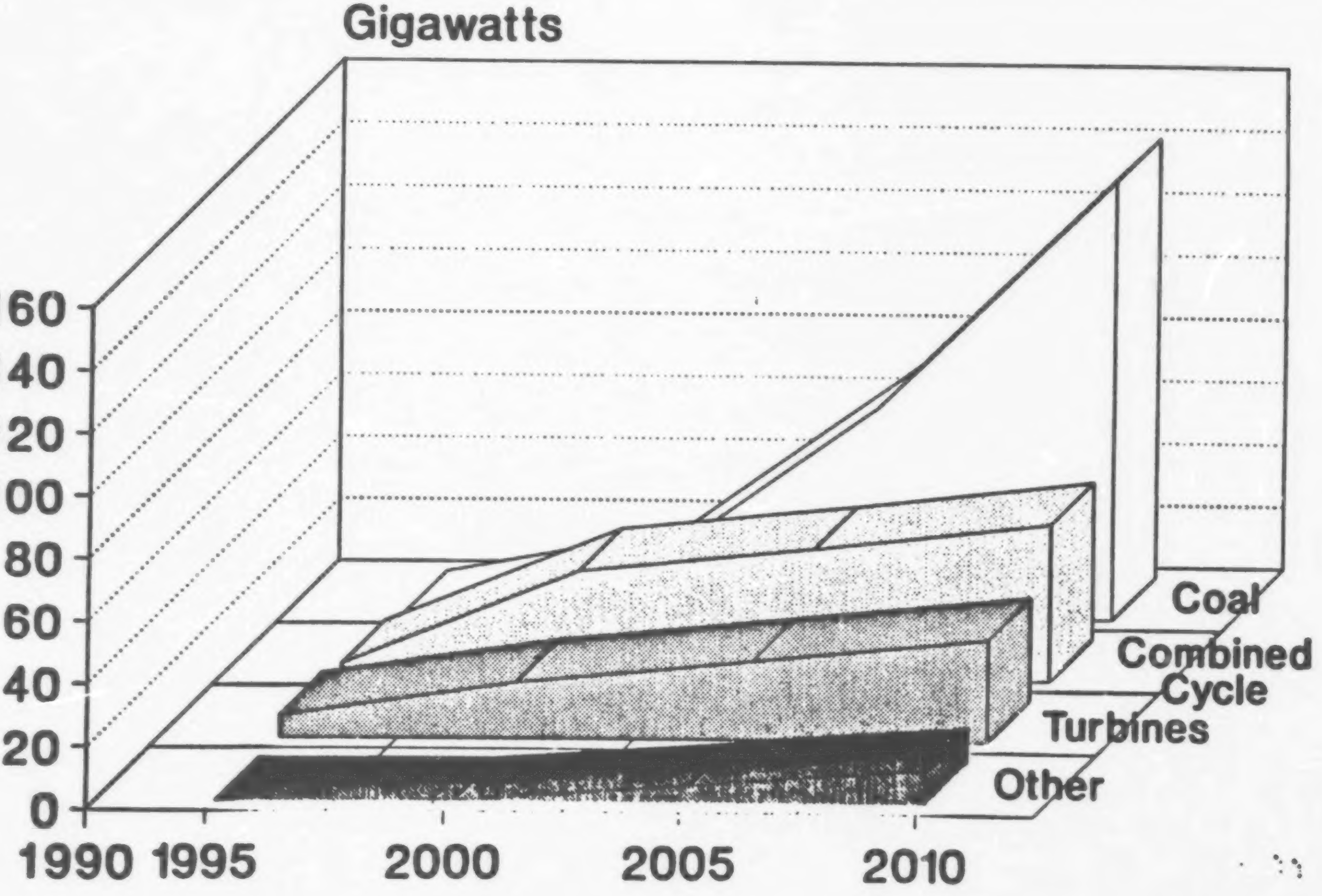


Source: Electric Power Monthly and Annual Energy Outlook, 1990

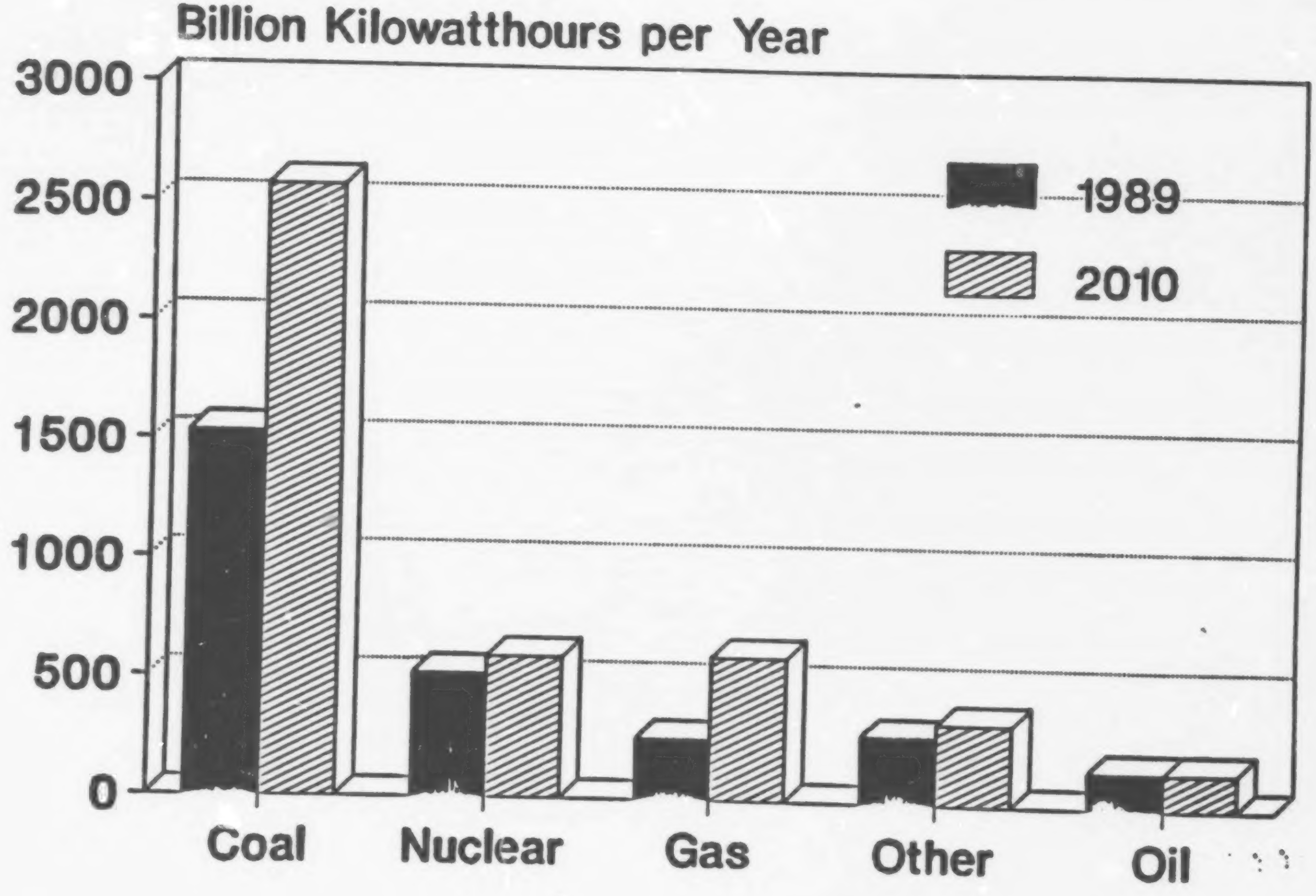
Fuel Shares for Total End-Use Energy Consumption



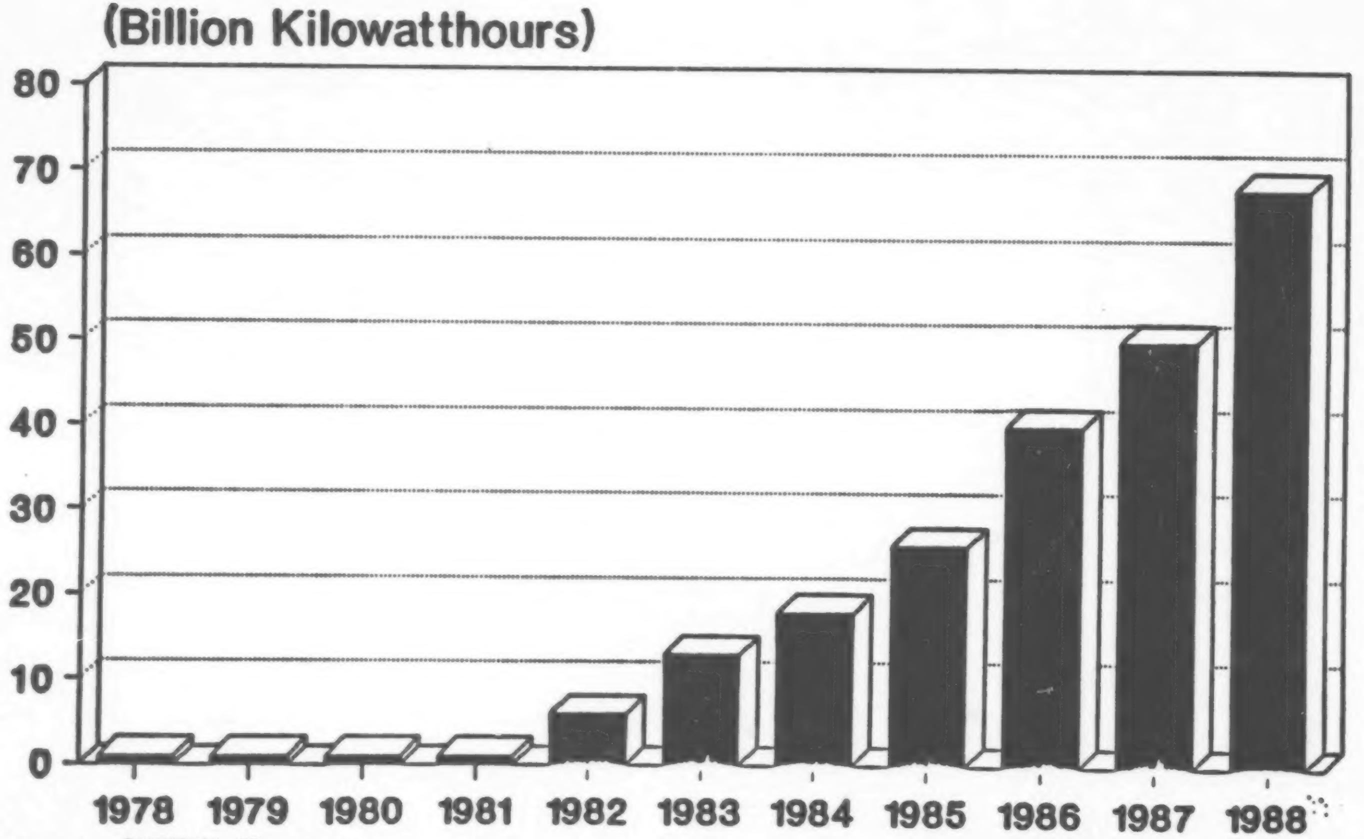
Cumulative Additional Needed Capacity, 1990-2010



Generation by Fuel Type, 1989 and 2010



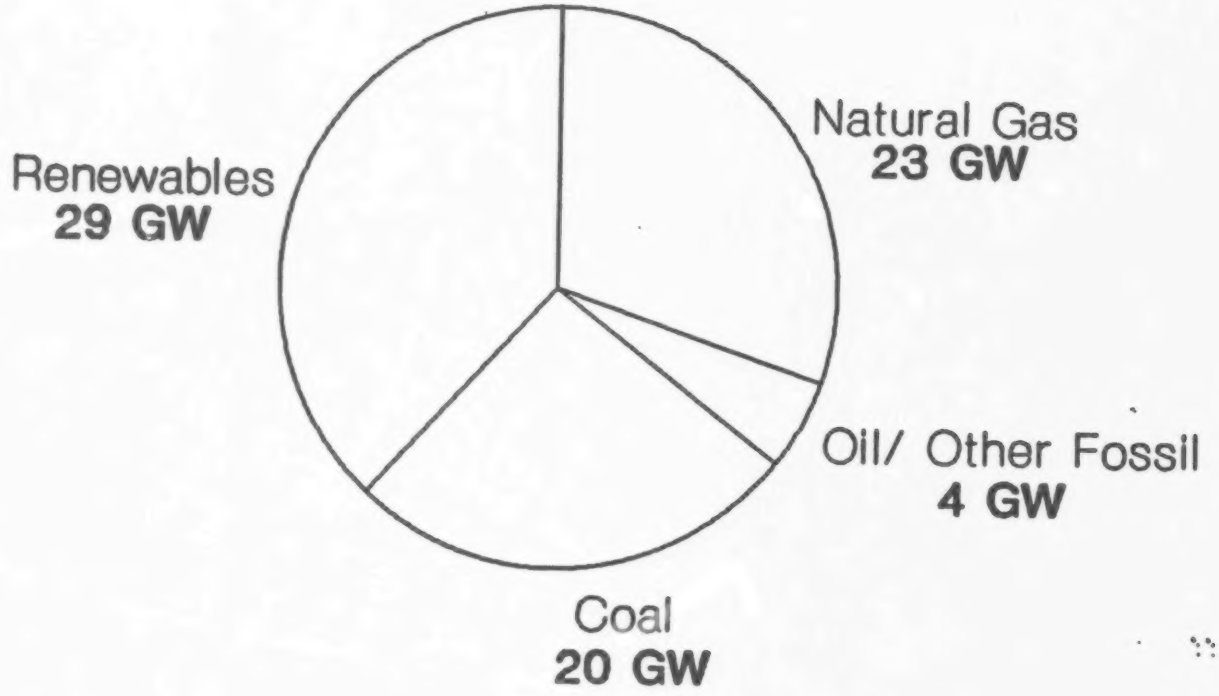
Nonutility Electricity Sales to Electric Utilities, 1978 - 1988



Source: FERC Form 1,
"Annual Report of Major Electric Utilities, Licensees, and Others." | Form EIA-861
"Annual Electric Utility Report" (1986-1988)

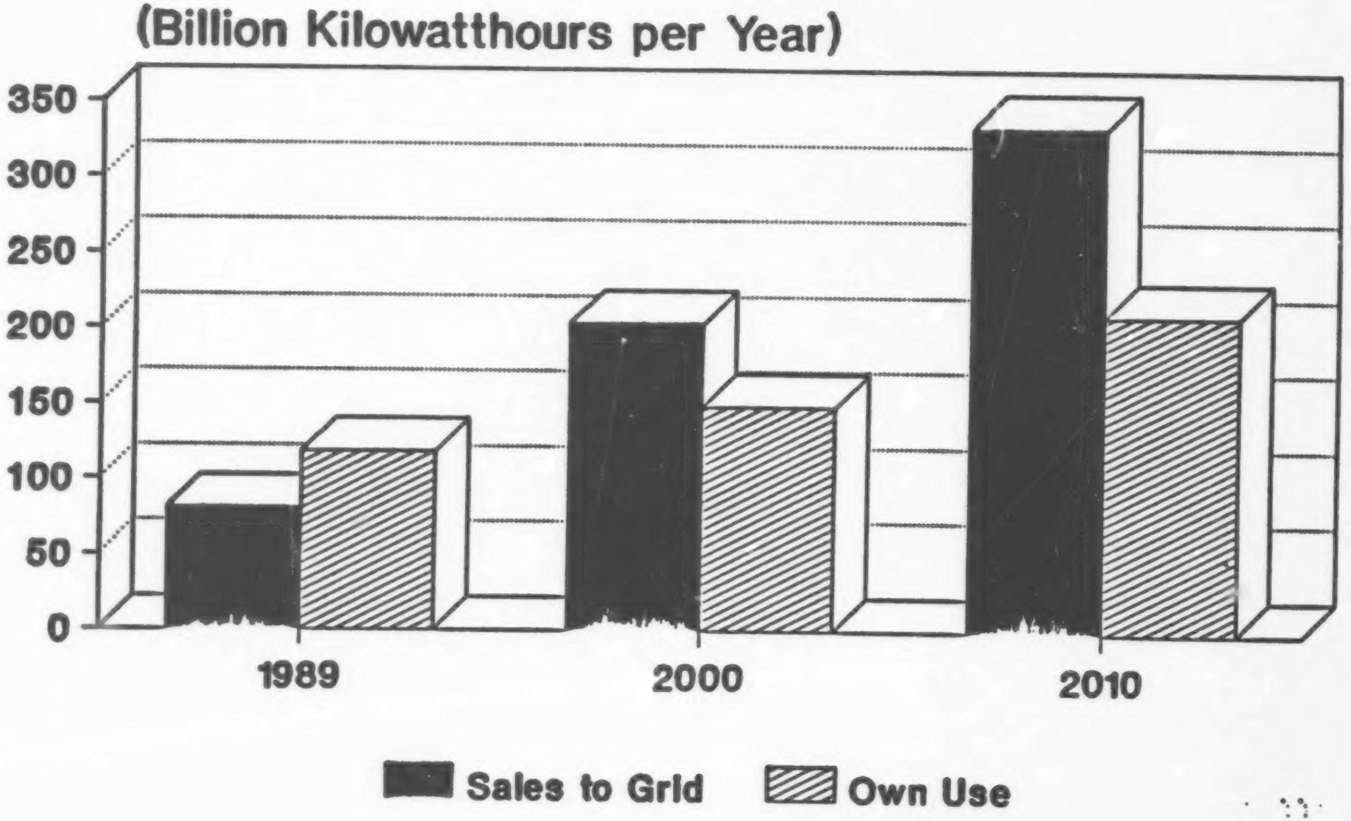
Nonutility Additions by Fuel Type,
1990 - 2010

(76 Gigawatts)



Source: Annual Energy Outlook, 1990

Nonutility Generation Projections
1989, 2000, and 2010



Source: Annual Energy Outlook, 1990,
Short Term Energy Outlook, 1990.

New England

	1989	1995	2000	2005	2010
Electricity Sales (Billion KWh)	104.7	127.4	145.0	162.4	180.7
Imports from Canada (Billion KWh)	5.0	14.1	24.4	24.6	24.9
Unplanned Capacity Additions (Gigawatts)	0	0	0	1.7	5.0

New York

	1989	1995	2000	2005	2010
Electricity Sales (Billion KWh)	192.5	233.5	264.7	296.5	330.5
Imports from Canada (Billion KWh)	4.2	14.6	16.4	16.9	17.4
Unplanned Capacity Additions (Gigawatts)	0	2.5	8.9	16.2	24.4

Midwest

	1989	1995	2000	2005	2010
Electricity Sales (Billion KWh)	490.3	585.6	666.1	739.4	821.4
Imports from Canada (Billion KWh)	0.3	5.3	7.7	7.2	7.2
Unplanned Capacity Additions (Gigawatts)	0	1.8	20.4	37.3	57.0

North Central

	1989	1995	2000	2005	2010
Electricity Sales (Billion KWh)	82.5	101.6	115.2	127.8	141.5
Imports from Canada (Billion KWh)	-.6	2.6	2.6	3.4	4.3
Unplanned Capacity Additions (Gigawatts)	0	0	1.6	3.9	6.4

CANADIAN ELECTRICITY EXPORTS: PLANNING AND PROSPECTS

Notes for an address by

Jacques Guevremont, Eng.

Executive Vice President

External Markets

Hydro-Québec

ENERGY AND ELECTRICITY

A Conference on Electric Power Planning in the 1990s

organized by

Canadian Energy Research Institute

Le Château Champlain
Montréal, Québec

June 3-5, 1990

1. INTRODUCTION

Good afternoon Ladies and Gentlemen.

Let me begin by saying that Hydro-Québec is pleased to collaborate with the Canadian Energy Research Institute in the organization of this conference. Such international gatherings are extremely useful for electric utility people like myself. Sometimes more can be accomplished in a three-day conference like this than in weeks of meetings and extensive travel.

Secondly, as a Montrealer, I would like personnally to welcome you to Montréal and to Québec. I hope you have a pleasant few days.

My subject today is Planning and Prospects in Canadian Electricity Exports. My remarks will first deal with the history of the trade, followed by the factors that favour it and the geographical areas where it can be expected to grow. I shall then look at some of the obstacles or limiting factors that must be overcome and then conclude with an assessment of what the challenges are for those responsible for planning the trade.

2. BACKGROUND

It is almost a platitude now in energy circles to point out that the Canada-U.S. electricity trade has been a great success story. Nevertheless, a short review of this trade with some interesting facts and figures should help us understand how this trade has earned that reputation and how and why it can be expected to develop in the next 15 years.

You may not realize it, but Canada is the largest electricity exporter in the world. This fact most likely places the only customer Canada has now, namely the United States, among the world's largest electricity importers. You'll note that I say

"NOW", since serious research projects are under way at Hydro-Québec to explore the possibility of exporting electricity to Europe by transforming it into hydrogen. But that is still a long way off.

The cross-border trade in electricity dates back to the early part of this century. Until the early 1970s Canada's electricity exports were generally counterbalanced by imports of equivalent amounts. In that period, one could best describe the trade as a useful load management tool for utilities on both sides of the border and as an added incentive to build generation facilities.

As you all probably know, the trade really took off in the early 70s. Whereas in 1970, Canada's net exports totalled only 2.4 billion kilowatthours, for revenues of $23 million, in 1987 the country exported close to 45 billion kilowatthours for net revenues of almost $1.2 billion. This rapid growth is indicative first of the availabiliy of Canadian energy at attractive prices and, second, of the capacity for rapid adaptation of both technology and the regulatory environment.

To put the electricity trade into perspective, consider that apart from automobiles and associated parts, for which net exports exceed $1 billion but which benefits from the auto pact, Canadian exports in single-product categories in the billion-dollar range are in primary products or raw materials. Therefore, we can safely say that trade in electricity has joined the big leagues. Furthermore, since electricity is a manufactured product, this trade helps to eliminate Canada's age-old reputation as a "hewer of wood and drawer of water" for others.

3. INTERNATIONAL ELECTRICITY TRADE - WHAT FAVOURS IT AND WHERE

Now let us look at what factors favour this trade, where the trade is strongest and where it can be expected to grow.

1. INTRODUCTION

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3.1 US Demand

The obvious reason for the rapid growth in exports has been the growth in US demand, due first to the increase in oil prices and second to the difficulties encountered in commissioning new nuclear and coal-fired thermal facilities. U.S. demand however is not equal from coast to coast.

In its comprehensive report *Canadian Energy* published in September 1988, the NEB pointed out that the Northeastern United States, and particularly New England, was confronted with the most serious energy supply problems in the US and that this supply deficiency would probably persist well into the next century. It indicated that these states would therefore be turning to imports from Canada as a serious long-term firm supply option.

On the other hand, Michigan and Ohio are in a surplus situation which, according to the same NEB report, should hold until the year 2000. The same can be said for Minnesota and the Dakotas. In the short term, this factor, perhaps more than any others, will limit electricity exports from Ontario, Manitoba and Saskatchewan.

In fact, the only area in the United States which is comparable to New England and New York in terms of supply needs is West Coast and, more specifically, Southern California. It is predicted that with the specific provisions in the Free Trade Agreement, BC's access to that market will improve in coming years.

3.2 Climate

Another factor, the climate, will also favour the development of the electricity trade, and specifically with customers in New York, Southern New England and Southern California.

US weather reporters never stop talking about the "cold air coming down from Canada," and our weather reporters complain about the "heat waves rolling in from the U.S.." This means of course that now and for the foreseeable future, the regions in the United States that I mentioned earlier have a pronounced summer peak, and the corresponding regions in Canada have a winter peak.

The **North American Electric Reliability Council** (NERC) has published some interesting figures on winter versus summer peaks in the different North American regions. NERC takes the summer peak for each region and expresses it as a percentage of the region's winter peak.

To make my point, I'll refer to two NERC regions namely the Northeast Power Coordinating Council, or NPCC, which encompasses New York and New England in the US, and Québec, Ontario, New Brunswick and Nova Scota in Canada, and the Western Systems Coordinating Council or WSCC, which encompasses West Coast and Rocky Mountain states in the US and Alberta and BC in Canada.

The report reveals that summer peak for all of NPCC-Canada will remain less than 70 percent of the winter peak for the next ten years, whereas NPCC-US is tending towards an even greater summer peak. Similarly in WSCC-Canada, the summer peak should remain at about 80 percent of the winter peak for the next ten years, and WSCC-US, like its northeastern counterpart, will be registering an even sharper summer peak in coming years.

These facts will obviously make long-term seasonal power and energy agreements attractive for parties on both sides of the border as an alternative to expensive peak capacity additions. It should be stressed here that virtually all Canadian utilities stand to gain from seasonal power and energy agreements, and this will most likely be an area of expansion.

The various forms of seasonal agreements, and incidentally, energy banking agreements could be considered to be a form of seasonal agreement, are alone justification for the construction of interconnections between neighboring systems.

3.3 Trade favours environmental protection

Inasmuch as environment issues are a constraint to any form of energy production development, they are also constraints to the electricity trade. I shall deal with this shortly. However, I want to stress that the international electricity trade can and does contribute to the protection of the environment.

In the 1988 report on *Canadian Energy* which I referred to earlier, the NEB estimates that Québec and New Brunswick exports to the United States will represent approximately 10 percent of electricity generated from thermal sources in New York and New England. It also adds -- and this is the interesting point -- that this will result in an equivalent reduction of acid-rain-producing gases. This fact should be taken into consideration in areas like Québec and New England that are particularly hard hit by this form of pollution.

3.4 Potential

Another determining factor in this trade is, of course, potential. At the risk of being accused of being biased, I shall limit my discussion of potential to hydroelectricity, for the simple reason that it is more difficult to talk of potential with other forms of energy. Nevertheless, I invite my colleagues from other Canadian utilities to speak up after if they feel they have been shortchanged.

According to the report entitled Electric Power in Canada 1988, published in 1989, Canada has an undeveloped hydroelectric potential of more than of 46 000 megawatts which can be considered economically, environmentally and technically viable. This is described as the planning potential based on documents produced by all Canadian utilities. It includes the Yukon and the Nortwest Territories.

Québec alone accounts for approximately 40 percent of this potential with some 18 000 megawatts. BC is second with 10 500 megawatts, followed by Manitoba. These planning potential figures obviously have an impact on the scope and nature of what will be on the electricity export negotiating table in coming years.

As for what part of this potential Canadian utilities are prepared to make available, I can only speak with authority about Hydro-Québec's situation. In short, Hydro-Québec has been working for several years now to reach long-term firm power and energy agreements for 3 500 megawatts by the year 2000. We are very confident that we will reach this objective in the near future, since contracts are already signed and approved for two thirds of this objective, or 2 200 megawatts. Furthermore, serious negotiations for additional blocks of power are under way which, once concluded, will push this total substantially above the 3 500-megawatt objective. We are now in a position where we will not be engaging in any new negotiations for power to be delivered before the year 2000.

4. CONSTRAINTS TO THIS TRADE

In any discussion of the future of the electricity trade between Canada and the U.S., the constraints or obstacles to the development of this trade must be addressed. What are they and how are they met?

4.1 Distance

First of course is the distance between generating facilities, particularly hydro, and load centres. Hydro-Québec earned international recognition when it commissioned the world's first 735-kV transmission line in the 1960s. This technology has been mastered and it is used to span the great distances that separate our major water reserves and our load centres.

Nevertheless, in order to deliver the 18 000 megawatts of hydroelectric potential which I mentioned earlier, another eight long-distance 735-kV lines must be built over the next 20 years. I can safely say that this transmission problem is common to all Canadian utilities. American utilities that import electricity also address this problem. And although it has been mastered technologically, it does pose a number of environmental problems.

4.2 Environment as a constraint

This brings me to talk about the environment issue. There can be no mistake about it, the environment is a constraint to development of the electricity trade. Sustainable development is a concept most of us subscribe to, but it means larger budgets, longer lead times before commissioning of new facilities, and modification or even cancellation of projects.

Allow me to explain. For Phase I of the La Grande project, the Hydro-Québec budget for environmental mitigation and enhancement measures exceeded a quarter of a billion dollars, or approximately 2 percent of total project cost. More than 200 scientists contributed to Hydro-Québec's bio-physical knowledge of the territory, some 9 million trees were planted, an ongoing environment monitoring network was established which is unique in the world by its scope and nature.

As for commissioning schedules, they can be totally modified in order to limit or avoid negative impacts. Take the 8000-megawatt Nottaway-Broadback-Rupert complex, for example. Until 1989, all projects on that complex were to start up simultaneously. However, results of our cumulative impact study have prompted us to develop this complex in four completely distinct phases.

In other cases, projects themselves can be considerably altered. The 450-kV direct current line from the James Bay area to the U.S. border is a case in point. This line must cross the St. Lawrence river which is an important part of our cultural heritage. All previous crossings of the St. Lawrence are overhead lines. High-voltage underwater lines are extremely expensive and the technology has not been completely mastered. Nevertheless, in order to protect the environment, we have decided to put that DC line crossing and all future crossings under the river - all of this just for esthetics.

Maintaining and protecting the human environment is even of greater importance. For example, Hydro-Québec is a signatory of the landmark James Bay and Northern Québec Agreement and of five subsequent agreements with Québec's Native Peoples. Under these different agreements, Hydro-Québec has committed close to 350 million dollars as financial compensation for any possible deterioration to lands and traditional Native ways of life. I remind you here that this is over and above the quarter of a billion dollars I mentioned earlier for environmental mitigation and enhancement.

If we add to this amount the financial contributions of the Québec and Canadian governments to Native Peoples, we arrive at a total compensation of over 750 million dollars for the preservation of the natural and human environment.

4.3 Interconnection capacity

Another limiting factor is interconnection capacity. This factor comprises stability and reliability considerations as well as the ability of receiving utilities to transfer the power to their load centres.

For example, although New York State and Québec have an interconnection capacity of 2600 megawatts, New York can receive only 2175 megawatts due to bottlenecks in their system. This limit will gradually rise to the actual interconnection limit of 2600.

The example of our link with the New England Power Pool is also interesting. This year our interconnection capacity with NEPOOL will be boosted from 690 to 2 000 megawatts. Two important commissionings will make this possible. In Québec our 450-kV direct current line from James Bay to the U.S border will be brought on line, whereas the DC line from Comerford in New Hampshire to Sandy Pond in Massachusetts will be commissioned in the United States. Through this, the Boston area will be directly linked with our La Grande generating facilities.

System compatibility can also limit exports. Until 1972 all U.S. imports from Hydro-Québec came from facilities islanded onto U.S. power systems. Now however, most power is exported via direct current links which means neighboring power systems need not be synchronized. Operating and design criteria of the trading partners' systems must be harmonized, though, to avoid serious problems. The NPCC has set the United States import limit from the Hydro-Québec main grid at 2200 megawatts until this harmonization has been completed. For our part, the necessary money -- some 850 million dollars to be exact -- has been budgeted to overcome this obstacle.

4.4 Free Trade vs reality

Now what about the Free Trade Agreement?

As the saying goes, "the tongue is ever turning to the aching tooth". This agreement which is now into its second year is off to a rather slow start. The preamble of the Agreement states that our two governments resolve "to create an expanded and secure market for the goods and services produced in their territories." One of the U.S. goals in negotiations was to obtain access to Canadian energy sources, whatever they be. And one of Canada's goals was to gain greater access to the U.S. energy market. These goals are reflected in Chapter 9 by the removal of specific barriers to the energy trade.

Paradoxically, the expressed wishes of our two countries for freer energy trade are having a hard time becoming commercial reality. The federal Energy Minister Jake Epp put it quite succinctly recently in a speech in Toronto when he asked "Will environmental regulation replace economic regulation as the key non-tariff barrier of the 1990s? There are many in Canada who seemed worried about such an outcome."

The Québec-Maine firm power and energy contract is a case in point. Here the parties had reached a mutually beneficial agreement for the trade of an obviously competitive energy product, however, a U.S. state government institution, the Maine Public Utilities Commission, decided to block it.

5. PLANNING

Planning the international electricity trade is a challenge. In fact, my colleagues from other Canadian utilities would probably say that is the understatement of the year. Sometimes I even think it would be easier if we had a crystal ball. There are just so many variables and unpredictables. And this is the case on both sides of the border.

For utilities like Hydro-Québec, for example, that count on a high hydroelectric component in their supply, the weather is an important factor, and I am sure you will all agree that nothing is harder to predict than the weather. And what about the oil, coal, and gas prices that economists and politicians always try to get a jump on but rarely succeed; or the regulatory environment which ebbs and flows with markets, the state of the economy, public opinion and so on. Then there is the demand growth rate, which must be predicted with reasonable accuracy many years in advance due to the long lead times required to bring new generation on line. Everybody was caught off guard by the recession in 1981. And there is the environment which, on the one hand, presents some very concrete problems to solve, but also comprises the much fuzzier issue of public perception of such problems and public priorities. For example, which is more important, the esthetics of the St. Lawrence River Valley or the water that flows in the river? Where should the money be spent?

In the planning process, electric utilities on both sides of the border must take all of these factors and many more into consideration before entering into long-term export or import agreements.

6. CONCLUSION

By describing the limits and problems in the international electricity trade, I do not wish to give the impression that they outweigh the potential for development. If that were the case I would probably not be speaking at this conference, and the utility I represent would not be so active on the American market. My goal is to be frank and to paint an accurate picture.

Personnally, I think the future is promising. We made a tremendous leap forward between 1970 and 1980, and maintained the level of the trade through the 1980s. The interconnections are in place on the drawing board to facilitate the trade. The Free Trade Agreement addresses the question specifically and new Canadian legislation has eliminated some regulatory duplication and created a fast track for obtaining export licences. And lastly, the demand is there to be met and Canadian utilities have the potential to meet it.

I often cite a C.D. Howe research institute report which called the Canada-U.S. electricity trade "one of this century's outstanding success stories." Frankly, I see no reason why this success story will not continue into the next century.

Thank you for your attention.

ELECTRICITY TRADE – A NORTHEAST PERSPECTIVE

Remarks by

Henry Lee
Executive Director
Energy and Environmental Policy Center
John F. Kennedy School of Government
Harvard University

for the

Canadian Energy Research Institute Conference
Energy and Electricity:
Electric Power Planning in the 1990s

Le Chateau Champlain
Montreal, Quebec

June 4, 1990

I appreciate the opportunity to join you this afternoon, and I would like to thank Gerry Angevine and the Canadian Energy Research Institute for their kind invitation.

New Englanders have many historical and personal ties to Canada which, in recent years, have grown stronger, in part due to the linkages forged through increased energy trade.

I have been asked to make a few random remarks about the emerging market for Canadian electricity exports and then provide a few comments on the presentations given by my two colleagues on this panel, Bob Eynon of the U.S. Department of Energy, and Jacques Guevremont of Hydro Quebec.

The decade of the 1980s witnessed a phenomenal growth in Canadian electricity exports to the United States, and especially to the Northeast. These exports occurred in a political and economic environment characterized by significant supply uncertainties, and an investment climate distorted by regulatory decisions resulting directly from the massive cost overruns in the U.S. nuclear program.

While environmental regulations and the tightening of transmission availability created difficulties for the utility industry, they were not constraining factors. Many Qualifying Facilities and Independent Power Producers were able to obtain necessary environmental permits, and, despite frequent complaints, arranged for transmission services. Finally, New England utilities and their regulators discovered that demand-side management could not only reduce their need for additional power, but might become a profit center for their industry.

On the other side of the border, Quebec and Ontario began the decade with a surplus of power and an interest in selling interruptable electricity at discounted prices, but by the end of the decade the situation had changed. Ontario now faces seasonal supply constraints, and Quebec, while possessing a large potential for future power development, finds itself struggling to meet its winter peak demand. While sales of surplus interruptible power will continue during our summer peaks, the days of large amounts of discounted imports are over.

While there remains an interest on the part of Hydro-Quebec to sell more firm power, this incremental electricity will only be sold at full market value. Given all of the uncertainties characterizing energy markets, it would be unreasonable to expect Hydro-Quebec to embark on the large-scale undertakings necessary to open up new hydro sites in Northern Quebec without some guarantees that those investments will provide substantial benefits to the people of Quebec. This reality is becoming better understood in the Northeast than it was five years ago.

The situation in New England is also changing, and I would like to touch on several factors which will affect power planning for at least the next decade.

Supply

New England is emerging from a period of uncertainty about the availability of sufficient power supplies to meet seasonal peaks. To some extent, the region has been very fortunate in that the weather has cooperated. The summer of 1989 was not that hot and the winters of 89 and 90 have not been that cold. This fact, together with a mild recession which is beginning to take hold, has allowed New England to escape the prospect of increasing brownouts and the threat of actual blackouts. Starting in the Fall of 1990, and continuing through 1992, approximately 3,000 megawatts of additional power will come on stream. These additions, together with another 800 - 1000 megawatts which are obtainable from demand-side management programs, will increase New England's capacity by approximately 17%.

Over the past 28 years, New England has increased its demand for electricity at a rate of 2.7% per year. My guess is that the present economic recession should continue at least for the first two years of this decade, and, as a result, actual growth in electricity demand for the period 1990-1995 probably will be closer to 2%. The end result is that New England will have a small surplus of power for the first half of the 1990s.

However, if the region wants to efficiently meet its need for additional power supplies in the second half of this decade, it will need to plan for those investments today.

Unfortunately, the political environment is going to make this process very difficult. Given the prospect of a short-term surplus in the region, I fear that it will be much harder to arrive at a political consensus as to what actions should be pursued. Without this consensus, it will be very difficult to site additional power facilities or large transmission lines.

My guess is that this political situation will create a continuing cycle in which the region goes from shortages to surpluses and then back to shortages again.

There are two exceptions to this situation. One is New York City and the other is Long Island. Both of these areas are in need of incremental supplies, and I feel confident that they will end up buying the power outside their utility franchise areas. If it is difficult to site a new facility in New England because of the lack of remote sites, it is even harder to do so on Long Island.

Transmission

Historically, transmission has been a very small part of the cost of providing electricity and therefore has never received much attention. There has always been sufficient capacity to move power within and between franchise areas. Prior to the 1980s, siting large transmission lines was not difficult.

Today, the situation is very different. In most parts of the United States, there is a growing realization that spare transmission capacity is beginning to disappear. Utilities are already fighting with each other over problems relating to loop flows, and private utilities and Independent Power Producers alike are concerned about their access to transmission, especially interstate transmission. At the moment, there are few incentives for utilities to build incremental bulk transmission facilities. Further, in the U.S there are no institutions to ensure that the country has sufficient interstate transmission capacity or even to arbitrate problems regarding use of the existing system.

Over the past two years, there have been major bottlenecks in moving power between states. This situation will grow significantly worse before it gets better.

On top of these regulatory problems, there is a very real concern for the environmental effects of high voltage direct current transmission. These questions center on three issues: air ions, electric fields, and magnetic fields. These emerging problems only compound the normal difficulty in siting power lines through local communities, which often perceive the line as providing benefits to distant consumers at their expense.

In summary, a transmission policy crisis is emerging in the United States, and it is one that is largely not understood by policy-makers. The issue is simply too complicated and, as long as power continues to physically move, it will be easier for governments to ignore these issues. I believe that this luxury, i.e. that of burying one's head in the sand, is one that will disappear rather rapidly over the next three years.

Environment

Before Thanksgiving, the United States Congress will pass a new Clean Air Act. This bill has many new provisions in it, but one that will have a dramatic effect on future regional power planning will be the new "allowance" system for sulfur emissions. Starting in 1995 and then escalating at the turn of the century, new facilities will have to purchase "allowances" either from other utilities or from an EPA administered auction.

This system will put a premium on natural gas, which in turn will be translated into higher gas prices for all users throughout the United States.

It is my belief that this system will be a factor throughout the 1990s, but will only really begin to constrain decisions in the period between 1995 and the year 2000 -- which is exactly the time when the Northeast will be looking for incremental power supplies.

Others

There are two other factors which are being ignored at the moment. The first is that slowly but surely the oil market is beginning to tighten. My guess is that we will not be returning to an era of higher prices for at least another two years, but beginning somewhere between 1993 and 1995, increases in world oil demand will erase the surplus we have enjoyed for the past ten years. Whether we will be paying $28 for a barrel of oil or $40 will largely rest on supply decisions being made by one country -- Saudi Arabia. This creates a very uncertain situation, since over the long-term most other energy sources are still pegged to oil products.

Finally, while there are enormous scientific uncertainties surrounding the issue, my guess is that the global warming problem is not about to go away. Whether world leaders agree on a reduction plan in the next two years or the next eight years, it is likely that some plan will be put into effect. One of the major targets will be electric utilities and, more specifically, those electricity plants fueled by the one energy source that the United States has in large supply -- coal.

Both of these factors, a much tighter oil market, and an internationally negotiated reduction in CO_2 will present major problems for energy planners.

My conclusion is that the Northeast has two choices. It can look at the next three years as a nice time to relax, go to the beach, and forget energy issues, and by so doing lay the seeds for a crisis situation at the end of the decade.

Or it can use the window of opportunity to develop a coherent power strategy to meet its future needs in an environmentally sensitive and cost effective fashion. It is my belief that Canadian power, and more specifically power from Quebec, New Brunswick, and perhaps Nova Scotia, can play a major role in such a strategy.

Which of these paths the Northeast will choose is very uncertain.

Demand Side Management: The United States' Perspective

by

A. Joseph Van den Berg
Director, Technical Services
Edison Electric Institute
Washington, D.C.

and

Clark W. Gellings
Director, Customer Systems Division
Electric Power Research Institute
Palo Alto, CA

June, 1990

[COVER SLIDE -- DSM]

[SLIDE 1]

Long regarded as a "natural monopoly," the U.S.'s electric utility industry is now entering an era of increasing uncertainty and complexity. Once unquestioned territorial boundaries are being encroached upon by neighboring utilities, with each passing week environmental issues continue gaining a higher public profile, and control over power supply is being challenged by third-party power producers.

[SLIDE 2]

After the 1973 oil embargo, historic U.S. electric energy growth patterns underwent a major change, with growth rates dropping from a very steady 7.5% annual rate to a rate that until 1988 has averaged only 2.7% per year. The future of electricity growth is less clear in the 1990's. Will the U.S. dependence on electricity continue to grow, and, if so, at what rate? Forecasts for peak demands in the 1990's range anywhere between 1.2 percent per year, to a 2.5 percent per year. Available resources are anticipated to exceed a moderate demand growth rate of 2 percent a year, until about the year 1995, after which supply is expected to fall below this mark.

[SLIDE 3]

Another uncertainty is a changing supply-side picture that includes a host of competitors who are viewed both as opportunities and threats.

[SLIDE 4]

Regulation and legislation issues--such as difficulty in power plant siting and licensing, least cost planning requirements, regulatory incentives for DSM, energy conservation concerns, and volatility of load shapes--are gaining momentum and will only grow stronger in the 1990's.

[SLIDE 5]

In response to these conditions, many utilities expanded demand-side management (DSM) programs both as peak-load reduction strategy and as a separate cost-saving service to their customers, distinct from the "main" business of generating and transmitting electricity. Within this environment, utilities are not concentrating simply on forecasting customer loads, but are attempting to shape loads to meet utility objectives and customer needs. And because of the close inter-relationships many utilities now share with their neighboring utilities, these questions have become a regional issue, in addition to a specific service-territory issue.

[SLIDE 6]
As you're probably aware, DSM is the planning and implementation of those electric utility activities designed to influence customer uses of electricity in ways that will produce desired changes in the utility's load shape. While the objective of any DSM activity is to produce a load-shape change, the art of successful implementation and the ultimate success of the program rests within the balancing of utility and customer needs.

DSM programs can be roughly grouped under the six generic objectives for control of load shape shown here: peak clipping, valley filling, load shifting, strategic conservation, strategic load growth, and flexible load shaping.

[SLIDE 7]
Utility efforts to modify customer consumption patterns have steadily increased in recent years. EPRI has sponsored surveys of DSM activities since 1977. I will not cover the industrial market sector because industrial DSM programs in the U.S. are by nature highly company, as well as, customer specific. They do not lend themselves to comparisons on a national basis.

EPRI's latest survey was in 1988, on all residential and commercial programs being conducted in 1987. This survey indicated about a quarter of a million customers in commercial programs, and almost 13 million utility customers in residential programs.

[SLIDE 8]
A breakout by objective shows peak clipping to be the most widely used type of DSM program for both commercial and residential sectors. However the net impact of all DSM programs in the U.S.A. is to reduce demand below what would be projected without DSM. This results from two generic types of DSM programs with countervailing influences--those that reduce peak demand and those that increase it. The net of these countervailing forces is a reduction in peak demand in 2000 of about 43 gigawatts.

[SLIDE 9]
This chart provides the number of new DSM programs added each year. Examination of program implementation dates shows steady utility expansion of DSM programs over the years. As of 1988, we added approximately 100 new programs for a total of 1,022 residential programs.

[SLIDE 10]
As shown, load control activities account for over one-third of all reported residential programs, with more than one-half of these load control programs focusing on direct-supervisory control technologies using principally VHF radio and powerline

carrier equipment. In the thermal energy storage/dual-fuel heating program category, dual-fuel programs dominate, being included in 92 of 135 reported programs.

[SLIDE 11]
Shown here is a breakdown of the reported 139 thermal energy storage and dual-fuel heating programs by technology type. Together, residential space heating and water heating loads account for as much as 36 percent of residential electricity use, and therefore represent a noteworthy portion of utility sales to the residential sector. Of those programs dealing with a single technology, 29 percent target dual-fuel heating equipment, 20 percent are storage space heating equipment, and 10 percent target storage water heating. Thirty-eight percent of the reported programs involve the promotion or testing of two or more technology types. Dual-fuel heating is included in 51 of these 53 programs, raising the total number of dual-fuel heating programs to 92.

[SLIDE 12]
This slide gives you a graphic picture of the impact on reducing peak load and valley filling that a thermal energy storage system has compared to a conventional home's heating system.

[SLIDE 13]
Supervisory load control is one of the oldest demand-side management techniques employed by the utility industry. The first known application of load control in the U.S. occurred in the 1940's when several distribution cooperatives in Wisconsin installed ripple systems to control water heaters.

The most predictable DSM programs involve control of customer's energy-using appliances. Direct control enables real-time alteration of customer loads by cycling water heaters, air conditioners, and space heaters on-or-off during specified periods.

[SLIDE 14]
Local, on-site, and distributed control methods are customer-tailored, allowing customers to make some or all of the control decisions. These intelligent energy management options now communicate real-time control commands, electricity prices, and other information.

[SLIDE 15]
The 1988 EPRI survey shows that almost 4 million appliances in the U.S. are directly being controlled by utilities, with air conditioners accounting for 42 percent and water heaters for 37 percent, overwhelming all other technologies.

[SLIDE 16]
Energy management and control strategies are expanding from traditional direct supervisory control to emerging uses such as price or load factor manipulation and tracking.

[SLIDE 17]
As shown, VHF radio is the most commonly employed direct supervisory control communication technology, accounting for 56 percent of reported programs, and more than 75 percent of the direct supervisory control points. Powerline carrier, shown as PLC, is the second most common technology, accounting for 28 percent of reported direct control programs, and 13 percent of control points.

[SLIDE 18]
A breakdown of 384 load control programs shows by maturity that 89 percent are in operation, and 90 percent are the direct supervisory type.

[SLIDE 19]
By year, this graph plots the number of load control programs and control points. As indicated, the growth in aggregate load control programs leveled off in the early 1980's, whereas the number of control points continued to increase. This was due to the termination of some test programs and the conversion of other tests into growing, implemented programs.

[SLIDE 20]
In the commercial sector, program implementation dates show steady, although until 1987, much slower utility interest over the years compared to the residential sector.

[SLIDE 21]
As shown, supervisory load control activities account for almost 25 percent of all reported commercial programs, with thermal energy storage and dual-fuel programs accounting for approximately 17 percent.

[SLIDE 22]
Here is a breakdown of the commercial sector's electricity use by end-use, according to total electricity consumption, and contribution to summer peak. While lighting uses the larger amount of electricity, air conditioning contributes more to the summer peak loads of utilities.

[SLIDE 23]
Listed here are the dominant varieties of thermal energy storage and dual-fuel programs in the U.S..

[SLIDE 24]
By type, storage air conditioning leads all other types of thermal energy storage and dual-fuel programs combined, with approximately 58% of the total number of programs.

[SLIDE 25]
And during the next 20 years, the impact of efficient buildings and equipment on reducing summer peak demand will grow, with the commercial sector contributing the greatest gigawatt reduction, with an estimated 11.1 by the year 2010.

[SLIDE 26]
More recently the term Least Cost Planning (LCP) has come into use. LCP refers to planning of an electric utility in such a manner as to select the "least cost" strategy from a possible portfolio of both supply and demand-side management options.

State regulatory commissions have also been active in developing an LCP process. A recent EPRI survey identified the status of LCP activities in each state. Electrical resource planners in nearly every state either use or are considering least-cost planning (LCP). At least 43 states, shown here in red and orange, either have functioning LCP strategies, or are considering, developing, or implementing a planning process that will help find the balance of new generating facilities and demand-side management (DSM). Although in most of these states, regulatory commissions or legislative bodies lead the development of LCP procedures through mandate or through active encouragement of budding utility LCP processes.

[SLIDE 27]
Achieving better balance in our planning is our best hope for coping with an uncertain future. Well-balanced plans are much better able to deal with unexpected contingencies than are plans which focus on a single direction, thus making it difficult to adapt to changing circumstances.

[SLIDE 28]
The need for balanced planning comes in many forms. Competing near-term versus long-term objectives need to be brought into balance.

[SLIDE 29]
Important national goals such as economic efficiency, environmental quality, and national energy security involve utilities to a great extent, as everyone now realizes. Adoption of energy efficient technologies can produce benefits toward achieving all three goals, and those opportunities should be exploited fully. Instances where efficiency improvements have negative consequences such as, inadequate building ventilation--the so called "sick" building syndrome--or inadequate lighting, while saving energy, also detract from economic efficiency and should therefore be avoided.

[SLIDE 30]
A clearer understanding of how energy efficiency, productivity, and conservation interrelate can go a long way toward achieving greater balance in utility least-cost plans. Cost-effective energy efficiency measures is the common element. Pursuing non-cost-effective opportunities will bring plans out of balance.

[SLIDE 31]
A more difficult balancing act concerns regulatory philosophy and achievement of societal aims. Policy makers are going to have to decide what the proper balance should be for our industry in terms of more or less regulation.

[SLIDE 32]
The planning approaches that we have been discussing today are the lens through which these diverse societal concerns can be brought into focus. For LCP, or any of the other planning techniques to work properly, they must define the trade-offs between competing goals so that balanced solutions can be put into place.

[SLIDE 33]
My final message on DSM and LCP today is really an old saying put into different words, "the proof of the pudding is in the tasting". LCP must be judged by how well it works. At this point in time the verdict is still out.

[SLIDE 34]
One of LCP's most promising features is the societal consensus that can result from greater public scrutiny of utility plans. The Pacific Northwest, with its labyrinth of public involvement in power planning, appears to be benefitting in this way from least-cost planning principles. While consensus isn't always achieved, effective institutional mechanisms are in place to air grievances and address concerns. Evidence from other parts of the country is not so clear. Efforts in these states should be watched carefully for clues about what does and doesn't work toward achieving public acceptance of utility planning decisions.

[SLIDE 35]
Unexpected events are a fact of life. While it is impossible to predict their occurrence precisely, flexible plans such as those being developed by Southern California Edison can help with industry response once such events occur. Something to watch for when judging the effectiveness of LCP is how well they handle contingencies and unexpected deviations from original plans. In particular, pay attention to whether or not capacity additions are made any easier under LCP in those instances where consensus for such actions exist.

[SLIDE 36]
Finally, financial success is the bottom line for any business planning process, even one that gets as much public scrutiny as LCP. While it is much to early to judge, there are leading indicators to watch. One is the recent effort by the Maine PUC to change the rules of the game and move toward a ratemaking formula that is intended to reward utilities for DSM investments.

[SLIDE 37]
What does the future hold?

[SLIDE 38]
Utilities first saw their customers as meters. Then they began seeing them as appliances. Only now, with the advent of competition, are they beginning to see them for what they truly are, real people with the ability to make choices.

[SLIDE 39]
In DSM planning, customers are both a resource--for designing a DSM program--and as a service target--for receiving value in return for their investment.

[SLIDE 40]
I see the future as one where the customer will become an integral part of any utility's attempt to manage its customers' loads.

[SLIDE 41]
In the final analysis, utilities must seek out the participation of their customers in creating DSM programs. Both for the utilities load shaping objectives, and their customers' long-term satisfaction.

# # #

DEMAND MANAGEMENT IN CANADA

Presented by

Dane B. MacCarthy
Vice President, Energy Management
Ontario Hydro
Toronto, Ontario

CANADIAN ENERGY RESEARCH INSTITUTE
Montréal, Québec
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Today I would like to spend some time telling you about demand-side management in Canada - - why Canadian utilities are moving in that direction; some of the differences between ourselves and our sister utilities in the U.S.; the impact on our respective demand management programs; and, finally, I'd like to focus on Ontario Hydro and some examples of our successful and not so successful initiatives.

As many of you may be aware, several U.S. and European utilities made forays into demand-side management as early as a decade ago. Canadian utilities have been slower to adopt demand management for a number of reasons. However, we are clearly making up for lost time.

So why have we started down the demand management road. First and foremost, it's the prudent decision for any utility. Demand management means using our resources wisely and efficiently - - eliminating any wasteful or unnecessary consumption. Canadians, I'm afraid to say, are among highest per capita energy consumers in the world. So clearly there is significant potential to conserve.

And our customers agree. In a attitudinal study Ontario Hydro did last year, approximately 78 per cent of consumers believed conservation should provide a major portion of future electricity requirements rather than new generation. In another more recent study conducted for the Canadian Electrical Association, the percentage of Ontarians who think their electrical utility should actively promote conservation increased fourfold.

So, for publicly owned corporations, as the majority of Canadian utilities are, there is an ethical responsibility to reflect the public's interests and concerns regarding their electricity supply system. If they want us to explore the potential of conservation and demand management, we must do it. It's simply the right thing to do.

Another reason for demand management is the higher than expected growth in electricity demand over the past seven years. The 70's saw quite a decline in the growth in demand for electricity. The recession of 1981-82 reinforced that decline substantially. In fact, Ontario's demand for electricity actually dropped in 1982 for the first time in almost 40 years.

But as we moved out of the recession, demand for electricity grew much more rapidly than anticipated. While some Canadian utilities, notably Ontario Hydro and Hydro-Quebec, expected to have surplus electricity to sell for a few years, the increase in demand began to soak up that surplus very quickly.

Speaking from my own experience in Ontario, we had no sooner gotten programs in the field aimed at efficient but more diversified uses for electricity when it became clear that we simply wouldn't have that electricity to sell for very long. In fact our growth in demand has continued to grow at over five per cent since 1983. With no new capacity planned beyond our Darlington plant, we had to focus our efforts on just how we could meet these rapidly increasing future energy needs. Demand management was clearly an attractive option.

Another factor which has moved Canadian utilities toward demand management is environmental concern. Like all of industry, utilities are facing growing public opposition to any activities which could have a detrimental effect on the environment. The construction of virtually any new plant - - coal, nuclear or hydraulic - - will have a substantial environmental impact.

Environmental awareness has been relatively high in Canada for a number of years, perhaps higher that it has been South of the border. Witness our provincial government's acid gas control legislation which was in place seven years ago. One of the main thrusts of our regulatory process is clearly to ensure that all decisions made by utilities are measured against environmental criteria.

Here again demand-side management provides a very attractive alternative. Not only can it help meet future energy needs, it can do it with virtually no adverse impact on our environment.

These three factors - - higher than anticipated growth in demand, environmental concern, and the fact that it's simply the right thing to do - - have largely fuelled Canada's pursuit of demand management. However, it's important to note that the urgency of adopting demand-side management varies dramatically across the country. These three overall factors are common from province to province. But, ultimately, the individual conditions in each province govern both the speed and the nature of that province's demand management effort.

As I mentioned earlier, our sister utilities in the U.S., Britain, and Europe have done some pioneering work in demand management over the past few years. My colleague from the Edison Electrical Institute has just provided us with an excellent overview of what's been going on in the States and the direction of demand management activities there.

Speaking from Ontario Hydro's perspective, we have spent a lot of time researching and studying American demand-side management initiatives. And many of our programs are variations on something that was first tried in California, Florida, or New England.

But, if there's one thing I've learned over the past few years, there's no "one size fits all" approach to demand management. Programs that work for one utility don't always work for others. Perhaps one of the biggest challenges Canadian utilities face in adopting demand-side management is to realize the differences between ours and U.S. utility operations and how those differences will affect the success of any particular program. In short, you can't always import a solution. We in Canada have to recognize that we're playing with a different deck and we must adopt demand-side management to Canadian conditions.

Consequently, I believe it's useful to take a look at some of those differences and their implications. First, electricity prices. While prices vary from one utility to another across the U.S., they are generally much higher than in Canada. At about five cents per kilowatt-hour, Ontario's prices are just about the median level among Canadian utilities. This means there is much less flexibility in using pricing as a tool to encourage conservation among consumers. Clearly, a powerful lever in getting consumers onside is the ability to demonstrate real dollar savings. And, while lower electricity prices are good in themselves, they allow very little margin for this kind of leverage.

Second, regulatory climate. In the U.S., the whole regulatory climate appears to be a more rigid, adversarial process that it is in Canada. Many American utilities have been instructed by their regulatory masters to spend a percentage of their revenue on demand-side management programs. While this ensures a minimum level of investment, it doesn't necessarily result in the most appropriate or effective programs. By and large, regulatory bodies in Canadian provinces do not stipulate what a utility must spend on demand management. No arbitrary limits or targets are set by regulatory agencies. This can result in a better, more thoughtful and more targetted approach to demand-side management programming.

A third major difference between Canada and the U.S. is the predominantly public vs. private ownership of utilities. Just about all of Canada's electrical utilities are publicly owned whereas over 80 per cent of the utility business in the States remains in private hands. This results in, I believe, some fundamentally different perspectives on how each utility approaches the marketplace.

For one thing, publicly owned utilities are very likely to face more bureaucratic hurdles simply because they have an obligation to take into account more directly the public's views and concerns. As well, they may have to "sell" their plans first to the provincial government. Depending on the nature of the relationship between that provincial government and the utility, this process could be a slow and arduous one.

Privately owned utilities, however, face less of this kind of bureaucracy. They do have to ensure an attractive return on investment for their shareholders and meet regulatory requirements. But, ultimately, the decision to adopt demand-side management - - or any other strategic approach - - can generally be made more quickly and directly.

As well, for most utilities, demand-side management is a fundamental shift away from their traditional supply-oriented activities. The risks, costs, and benefits of any particular demand-side management option are much harder to calculate than those associated with a new plant or transmission facility. So publicly owned utilities are likelier to be more cautious in moving into demand management.

Related to this public vs. private issue, there is another difference between Canadian and American utilities - - geography. While U.S. utilities generally have the obligation to provide power to all consumers in their service territory, those boundaries have largely been established over the years by marketplace forces.

This is not the case in Canada. In most provinces, Alberta being the chief exception, the provincial utility is responsible for serving all consumers within that province. Now, that's not so very different than the service territories of U.S. utilities until you look at a map.

For example, in Ontario, there are 9 1/2 million people in a province of over 1 million square kilometres. And, about 90 per cent of that population is located in the southern portion of the province. As a public utility, we have an obligation to ensure that everyone in the province - - whether they are in downtown Toronto or just south of Hudson's Bay - - has access to electricity at the same unit cost.

From a supply angle, this has always been a dilemma. Obviously it costs a lot more to have the transmission and distribution system in place to serve the needs of the more remote parts of Ontario. From a demand-side perspective, one might be tempted to think that those additional costs won't apply. But, here again, if we are to maintain that principle of universal access, any demand management programs we undertake must be available to everyone in the province from Toronto to Hudson's Bay. As demand-side management programs tend to mean more contact with the customers, they are also more labour-intensive. This presents a substantial challenge in terms of cost and logistics to Canadian utilities moving into demand-side management.

One final difference I would like to point out is the differing marketplace conditions between U.S. And Canadian utilities. The nature of competitive forces and consumer expectations in the U.S. varies considerably from the Canadian experience. For one thing, there is much more competition among U.S. utilities for service territories. The growing influence of private generation is posing a competitive threat to many U.S. utilities. As well, American consumers are more accustomed to viewing electricity as a product "sold" to them by a supplier.

In Canada, there is no competition for service territories. A provincial utility serves that province, pure and simple. As there are no bottom line profits to be made, why should there be any competition for new markets? (Here again, Alberta is the only province served by two investor-owned and one publicly-owned utility.) Private generation is also not the competitive threat that it is in many parts of the U.S. This is due, in part, to the low electricity prices in Canada. It is not economically attractive for a company to get into the private generation business in any substantial way because they can't compete with the cost per kilowatt of most provincial utilities. If anything, utilities are actually to encouraging independent generation as a supplementary source of power for the future. For example, Ontario Hydro is aiming to encourage 1000 megawatts of independent generation over the next 10 years.

While I can't claim to explain all the implications, these marketplace differences may have a subtle effect on the way Canadian and American consumers view and adopt demand management. But, it is clear that while Canadian utilities can learn from the demand management experiences South of the border, we can't import programs wholesale. We have to tailor our demand-side management activities to our own needs and conditions.

I would like to give you a brief overview of what Canada is, in fact, doing on the demand side and then spend some time tooting my own horn concerning Ontario Hydro's demand-side management programs.

I don't claim to be an expert on the demand management scene across the country. Quite frankly, I'm run off my feet just keeping up with what's happening in my own shop! However, there are some significant activities being undertaken elsewhere in Canada and I'd like to highlight a few of them.

British Columbia has perhaps the most extensive demand-side management program outside of Ontario. B.C. Hydro started pursuing demand management about three years ago. About a year and a half ago, it launched "Power Smart", an umbrella identity for all its demand management programs. Its goal is to achieve annual energy savings of 3500 gigawatt-hours a year through 1998 - - about four times the amount of power now consumed by B.C.'s capital city, Victoria. And, to do this, it is investing $340 million annually in demand management programs.

When it was developing these programs, B.C. Hydro's objective was to get the best information available on demand management and adapt it to the province's needs. Or, as one of its senior executives recently said, "We stole from the best." I happen to know this is true because the Power Smart Energy Efficient Lighting Program looks remarkably similar to Ontario Hydro's!! With 14 programs now in the field, Power Smart has achieved total energy savings of approximately 68 gigawatt-hours to date.

Hydro-Quebec has also gotten on the demand management bandwagon recently. It, too, has been experiencing very high growth in demand over the past few years. Like B.C., it relies almost totally on hydraulic resources which, in the past few years, have been plagued by low water levels. As part of its "Horizon 1999" development plant, it has set a demand management target of 12,900 gigawatt-hours a year to 1999. It has earmarked $1.8 billion for this purpose and developed a comprehensive strategy aimed at reducing consumption and shifting load.

With much of its increasing growth in demand coming from the all-electric and dual heating requirements, Hydro-Quebec will be putting emphasis on reducing heating load through more efficient heating and insulation programs. However, it is a good example of a utility whose customers perceive that electricity is cheap and abundant. With over 10,000 megawatts of hydraulic potential in their proposed James Bay project, coupled with the second lowest cost per kilowatt-hour in Canada, it is difficult for Hydro-Quebec to convince its customers that conservation is a necessity. To counter this, it is launching a massive information campaign this year to build awareness of the need for conservation and to introduce a number of accelerated rebate and subsidy programs across all sectors.

While I don't want to give short shift to the efforts made by the other Canadian utilities, it's clear that Hydro-Quebec, B.C. Hydro, and Ontario Hydro have developed the most comprehensive demand management strategies overall. However, most of the other utilities have smaller-scale information and energy audit programs, either individually or in conjunction with their provincial governments or the Canadian Electrical Association.

I want to turn now to what I know best - - Ontario Hydro's demand management activities. Our demand-side management program has been developing since 1984 when the Corporation initiated a study of all supply and demand options we might pursue to meet future energy needs. After a number of years of research and study, this resulted in the Demand/Supply Plan which we released last December. It is a 25-year blueprint for meeting our future electricity requirements through a multi-faceted program of demand management, purchases from independent generators or neighbouring utilities, refurbishment of older plants, development of remaining hydraulic sites, and the construction of new capacity.

This plan must also be weighed against several criteria including cost, safety, social acceptability, technical soundness, reliability, flexibility, customer satisfaction and, perhaps most important, environmental impact. In fact, this plan will be reviewed over the next year before our Environmental Assessment Board. After they have reviewed it and made recommendations, it goes back to Hydro's Board of Directors for final approval and implementation.

Demand management is, in many ways, first and foremost among the options in this broad-based plan. For one thing, we don't need any formal legislative approval to proceed with demand management programs so we have been pursuing demand-side management activities for a few years now.

The past year or two, however, has seen an acceleration of our efforts. In fact, we expect demand management programs to meet 60 per cent of all growth in demand over the next 10 years. We have targetted a saving of 4500 megawatts by the year 2000 - - 1500 megawatts through information and awareness programs which should speed up the rate of natural conservation; 2000 megawatts through financial incentives for energy efficiency improvements; and 1000 megawatts of load-shifting primarily through the adoption of time-of-use rates.

I'm not going to go into a lot of detail about individual programs we have designed for our residential, commercial and industrial customers; however, I would like to give you an idea of the range of programs we are offering. In the residential sector - which also includes programs for our agricultural customers - we're heavily involved with programs in both the existing and new housing markets.

We're focusing on information about new home construction, energy efficient appliances, the R2000 energy efficient home design, blankets for water heaters, energy efficient showerheads, heat pumps, and a range of other low-tech,easy things for the customer.

In the commercial sector, we offer a wide variety of programs for the various market segments. In the office building segment, for example, we are advocating energy management control systems, internal source and ground source heat pumps, thermal cool storage, and high efficiency fluorescent lighting.

In retail stores, malls and plazas, we're supporting heat pumps including bivalent roof top units for strip malls, as well as high efficiency merchandise lighting.

In the hospitality sector, we're aiming for improved efficiency through heat recovery, energy efficient showerheads, installation of room occupancy sensors for set back thermostats, and the use of heat pumps. We're starting to get some excellent results from our commercial program efforts. For instance, our lighting incentives have resulted in about 20 megawatts of savings so far; we have four major customers lined up for thermal cost storage systems; and we've installed over 17,000 energy efficient showerheads in hotels and multi-residential buildings.

Turning to the industrial sector, our programs have four principal objectives. To raise awareness of and commitment to electrical efficiency in industry; to identify opportunities to introduce load shifting; to provide support for industry initiatives designed to improve energy efficiency; and help customers adopt energy efficient electrotechnologies.

Load shifting, as I mentioned earlier, is an area we're particularly active in with our industrial customers. In January of last year, we introduced time-of-use rates in the province. And about 70 per cent of Ontario Hydro's total load and 80 per cent of the municipal utilities' load for large industrial users is now billed under time-of-use rates. Almost 80 megawatts of savings were realized during the first year these rates were in effect.

In the time remaining I would like to highlight a few of the programs; and, finally, I want to leave you with some observations I've made over the past few years concerning the issues any utility must wrestle with when moving into demand management.

One of our first and most successful programs has been our energy efficient lighting program. As lighting represents 40 percent of the electricity used in Ontario's commercial sector, and 10 per cent of industrial consumption, there is a major opportunity for us to reduce consumption by encouraging businesses to convert to energy efficient lighting. in fact, if we could get every commercial enterprise to switch to energy efficient lighting, we could save up to 900 megawatts of electricity. So it's obviously an excellent means of reducing consumption. And it saves the customer a lot of costly maintenance work.

To make conversion attractive to commercial customers, we offered an incentive of up to 50 per cent of the conversion costs for customer switching to state-of-the-art energy efficient lighting. That's a good deal. We offered a couple of alternatives in terms of conditions.

This approach seems to be pretty successful. We've only had the program available for just over a year and we've saved 20,000 kilowatts so far. As we fan out this program even more through our friends in the municipal utilities and the lighting contractors and manufacturers, we expect these savings to grow exponentially.

I believe the critical elements in the success of this program is that it is a relatively simple technology. It has wide application. And it is easily leveraged through electrical contractors, consulting engineers, and other industry allies.

The lighting program is a good example of an incentive program that promises to bring in substantial megawatt savings and is precisely targetted at the commercial and industrial market sectors. But one of the objectives of our demand management efforts it to gain wider visibility of demand-side management activities among all consumers. While Ontario's residential sector represents only 30 per cent of all electricity consumed in the province, and the megawatt savings target for that sector is considerably lower than the other two sectors, it is the sector with the highest visibility potential. So much of our effort in the residential sector is to create the climate for consumers to conserve and to build awareness of energy-saving programs and opportunities available through Ontario Hydro.

Last fall we initiated a promotion of energy efficient household items in conjunction with a retail hardware store chain, Home Hardware. Over five million flyers were distributed to consumers in the province, reinforced by print and radio advertising. Each flyer contained 24 coupons good for up to a 40 per cent discount on items such as light timers, weatherstripping, energy efficient showerheads, motion sensors, timers for block heaters, etc.

By all indications, this promotion worked. Sales of those items increased 330 per cent over the previous fall. The public awareness of the need for energy efficiency and conservation increased significantly. Customers who participated in the program saved money. And the province conserved some much-needed energy for the future. So it was an all-round success. While the megawatt impact of this program was not substantial, it raised the profile and necessity of conservation across the broadest range of consumers.

But we haven't had all unqualified successes. In fact, we have had some programs which have required changes or adjustments to make them viable. One such program is our "Power Savers" audit program. Essentially an "identifier" program, it was designed to identify potential energy and money-saving opportunities among our commercial and industrial customers' operations. Under the program, auditors visit a customer site, do a detailed audit which is analysed and returned to the regional energy advisor. He or she, in turn, visits the customer, explains the findings of the audit and suggests some of the various financial incentive programs available through Hydro which the customer may wish to explore. In the 10 months this audit program has been available, over 1000 businesses totalling over 70 million square feet of space have been audited. Our target is to be up to 3000 audits per year by year-end.

While this program is promising, there are clearly a few bugs we need to work out to improve its effectiveness. For one thing, we may have underestimated the demand for audits when we first introduced the program. Because we have 12 auditors to serve the entire province of Ontario, the waiting list for audits is as long as two months in some cases. Another problem area we must address is that a contract auditor is performing the audit, the data is being analysed and compiled in a head office unit, and the regional energy advisor is the one who actually presents the findings to the customer. We are discovering that, in some instances, the advisors are not sufficiently comfortable with the data collection or analysis to "sell" the customer on various energy efficiency programs. So this is an example of a program that is excellent in concept but we may have to do a little more work to make it truly effective in practice.

Finally, I'd like to relate a few of the things I've learned during the last few years - - issues which, in one way or another, all utilities embarking on demand management, must face.

First, you must establish a philosophical framework for your demand management activities. You can achieve load reduction and shifting through a number of ways - - regulation, pricing policy, direct intervention, incentives, and so on. In a sense, we chose to use a carrot rather than a stick. We wanted to work with our customers to ensure that they got the best value for their energy dollar. So we have designed programs that allow them to better control their electricity bills. While our rates may be as high or higher than in the past, our customers have the tools to lower their bills.

Second, you come to terms with issues such as how you're going to handle "free riders" or how you will calculate avoided costs. What level of incentive payment is necessary? What is the market availability of many energy efficient technologies? These kinds of issues must be considered in order to develop an effective demand management strategy.

Third, administrative systems. We have learned the hard way that a consistent, across-the-board, approach to administering demand management programs is essential. Quite frankly, we started out with a bit of an ad hoc system and it became clear almost immediately that this was ineffective. Incentive payments must be processed quickly. Tracking must be precise and timely. Feedback from field staff is necessary for adjusting, improving and evaluating programs. If you are putting significant resources into designing and developing programs, don't ignore the importance of effective administrative systems.

Fourth, you can't do it all yourselves. Successful demand management programs depend on your relationships with allies. Leveraging your programs through equipment and appliance manufacturers, contractors, distributors is the only effective way of building megawatt results. The trick, of course, is getting them onside. You must make it worthwhile for them to get on the demand management bandwagon. In some cases, this means offering them a financial incentive directly. In others, it means giving them incentive packages they can use as "door-openers" in their customer contact. Sometimes, advertising and promotional support may be all that's required. But, whatever way you achieve it, good ally relationships are key to your success.

One final suggestion - - keep abreast of what's happening in other utilities. While I firmly believe that programs must be adapted to your own local conditions, we can all benefit from an extended network of information-sharing on demand management. You don't need to re-invent the wheel; however, you might want to add a few spokes to it.

In summary, I believe demand-side management is a fact of life for all utilities in Canada, the U.S., and elsewhere. It is increasingly part and parcel of utility operations. While the need for it and the specific potential varies across Canada, it is beginning to provide Canadian utilities with another valuable tool to meet future energy needs.

"CALIFORNIA'S EXPERIENCE WITH NON-UTILITY GENERATION"

Presented by

Commissioner Robert Mussetter
California Energy Commission

Energy & Electricity Conference
Montreal, Quebec
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To follow on after the previous speaker who invoked "Peanuts", I will refer to Li'l Abner Yokum, a cartoon character who was popular during my youth. As Li'l Abner would have said, "As any fool kin plainly see", there should be a lot more energy trade between the United States and Canada. That happens to be my view. And, I certainly think there is a great deal more trade that can and should be done between California, British Columbia and Alberta.

I think we had two very provocative presentations yesterday by Adrienne Kwazcek and Dr. Stalon. Adrienne said we ought to know what our goals are, and so far in this meeting, I have not heard anybody come forward in response to that. So, I will change it around a little bit. I think first we need to know what the heck it is we are fighting. Why is it that something that is "plain to see" is not happening nearly as fast as it might?

I believe there are two main reasons. The first is the Cold War. That has been the dominant condition in this world for 45 years. People, especially young people, have become inured to it. It may sound a bit bizarre to say this in an energy forum, but I think it is naive not to recognize it as highly probable that there are a few persons among us whose goal is to diminish the economic strength of both the United States and Canada. Their litmus test of success is to raise our prices. When they succeed, the living standards of our people are lowered, and discontent, or as Reagan called it, the "misery factor" increases. The point is, there are almost certainly some people in our midst actively and intentionally working against us.

The second reason is Parkinson's Law. You know his first law, "Work expands so as to fill the time available to complete it". But some of his other laws and corollaries are just as precious and are directly applicable to the energy and utility field. For example, "delay is the cruelest form of denial". That brings to mind the California Public Utilities Commission's (CPUC) well-established behavior in such matters as transmission line siting, interstate natural gas pipeline siting, and the proposed merger between Southern California Edison Company and San Diego Gas & Electric Company.

I liken the bureaucracy that has grown up to a compost heap. It is a fertile seedbed for the implantation of bad ideas. They grow and flourish in this environment.

The man to whom I owe my current appointment, Lyndon Baines Johnson, is the single individual most responsible for the ills we face today. I say I owe my position to him because he stimulated me to political action twenty-five years ago. Those of you my age will recall his "guns and butter" policy, in which he stubbornly pursued a land war in Asia while at the same time using his political skill and knowledge of the Congress to pass the "Great Society" legislation. Conservative economists of the day predicted wild inflation that would come several years later, and they were right on the money. Especially when we had a president, like Jimmy Carter, whose people let up on restraint just a little, and inflation burst through the roof with nearly

20 percent a year for 3 or 4 consecutive years. As John Maynard Keynes pointed out, inflation produces ills not one man in a million can diagnose.

That is the problem. Dr. Stalon emphasized the unravelling of the old compacts and the terrible consequences of all those old arrangements coming undone. Think of the "take or pay" fiasco in the gas business, and now the savings and loan debacle in the United States. These are the payoffs of inflation, and inflation originated years before in the foolish, yet stubbornly pursued, policies of our government. In many other aspects of our energy business we are subject to, and having extreme difficulty contending with, tremendous political and financial pressure resulting from those earlier policies.

California's experience with non-utility generation must be viewed against that background. We had, during the eight years following Ronald Regan (as our governor), a "small is beautiful" governor. At least, that was the inclination of his people when it came to electricity generation. For the most part, they were anti-nuclear and anti-coal. They were against big central power plants as a given. The utilities, for their part, had become arrogant. They stonewalled in the 60's and 70's and tended to react against "hippies" protesting at the University of California, and elsewhere. We had a confrontation we are still trying to get over, outlive and digest. If you want to understand why California has high kilowatt-hour prices, you have to begin in this context.

The CPUC took eight years to decide how it would price and administer Jimmy Carter's Public Utilities Resources Policy Act (PURPA) of 1978. During that eight years, market conditions changed completely; for instance, the price of oil broke, but economic sea-changes were largely ignored in the CPUC's deliberations. Though "small was beautiful", the CPUC's Jerry Brown appointees came up with an open-end contracting policy that resulted in 16,000 megawatts of projects signing up. These contracts were virtually unilateral, that is, the utility companies were obliged to enter them with anybody who had the desire. Desire is wonderful, but heretofore, in business anyway, for various good reasons it took more than desire to succeed. Not any more. Under the CPUC, we got a wad of projects big enough to choke a horse, much larger than any central plant would have been and at prices generally conceded to have been predicated on oil running up to $80 or $100 a barrel.

Instead of getting away from the lumpiness of big investment, we had a huge lump to plan around and digest. The contracts gave five years to build and come on line; this produced great uncertainty in planning and forecasting resources for the state. 16,000 megawatts is more than one-third the in place generation in California in those years. We are now reaching the end of the five-year contract lives, and it appears something more than 10,000 megawatts of those projects will actually come on line. The battle recently has been over the right to extend the deadlines, and interpretation of "force maejure" provisions in the contracts.

In evaluating "successes" or "failures", in my view the losers are wind, solar, and geothermal. This is viewed against the litmus of price. The winner is co-generation. In the 1990's the two big issues are repowering of older utility plants and trade, i.e., importation of energy including gas and electricity into the state to match its population and business growth.

Wind is a loser because it is not practical. The wind-driven motors are mostly induction motors. Expensive capacitors must be installed to enable the utility system to accept the electricity. Edison and the CPUC have not, according to my information, reached agreement on who is to pay for many of the necessary capacitors, whether it is to be ratepayers or shareholders who pay. So, for many of the machines, Edison pays the wind operators based on a formula approximating what they would get if their energy came into the system, but in fact it does not. I use this to illustrate some of the down side of renewables you seldom if ever are told. And, if this were not bad enough, during the summer "Santa Ana" winds, when air-conditioning demand is exacerbated, the windmills generally don't produce because they are limited to operations between wind speeds of about 15 and 35 mph. Yet, we have given tax credits, high prices, and special financing to wind machine operators who have littered the countryside at San Gorgonio and Altamont passes with their hardware.

Solar energy is accepted into the physical system better than wind energy. Yet, we have some improving to do here too. Present technology, exemplified by the "Luz" plants in the southern California desert, utilizes a toxic fluid to collect and convey heat, uses natural gas to augment its production, and costs ratepayers substantial premiums contained in their electric bills. Energy Commission staff analysis of the last two Luz plants to be licensed (in early 1990) disclosed $157 million of net present value cost when compared with other resources available to Southern California Edison Company. This cost was justified by valuing emissions reductions, including carbon dioxide emissions reductions, and we have thus created another mechanism that "not one man in a million can understand".

Geothermal might be fine and have a big future. I do not know. For the present, we are very worried about a twenty percent decline in energy output from the geysers in Sonoma and Lake Counties. While some may characterize this as being due to too many "straws" in the same pool (there are over 400 wells), it is in my view simply a natural reflection of the facts in the steamfield, that is, it is a finite, limited resource that we have not learned exactly how to manage. Our Commission has underway a cooperative effort with the parties in interest to determine the best way to manage this field in the future, and to accommodate as best we can the competing and conflicting interests.

Geothermal in Southern California is being developed using low temperature brines. These are extremely corrosive fluids. Nevertheless, at Coso and some other contract-holders' projects, so long as favorable pricing will allow, development will proceed.

Biomass is probably about a break-even proposition. Any time you go from liquid to solid fuel, as engineers will tell you, you increase your auxiliary load by a great deal and move into a different ball game. Your costs will be much higher than with liquid fuel. However, in California we had a lot of agricultural, timber and other wastes around the State that were being burned or otherwise disposed of. My staff tells me most of these wastes are now being utilized.

Co-generation is the real winner. I am not sure General Electric, Westinghouse, and the other manufacturers would have come up with the efficient gas-fired turbine configurations now available for electric generation if California had not led with its chin and its pocketbook. We have paid a lot for this progress that has now been made, so the rest of you can jump on the bandwagon and enjoy the benefits. They have turned out to be reliable pieces of machinery. The efficiency, reflected in the lowering heat rates, keeps improving. Progress in this field probably justifies a lot of the other nonsense that has gone on.

Now, however, we brilliant folks in California are embarking on a course that could greatly hamper our future use of efficient gas turbines which, for us, is the cheapest source we can add. I refer of course to the "global warming" scare and debate. Premature reaction by the legislature could easily lead to policies enshrined in state law that would charge a carbon tax on all fossil fuel sources, including out of state sources. That means you! It means you in Alberta, you in British Columbia, as well as producers in California and elsewhere, if even a so much as a tincture of, say, coal or gas-fired electrons "contaminate" their power.

The Energy Commission is mandated by the Legislature to recommend policy on "global climate change", as it's now euphemistically called (this is derived from the fact that equally credible groups of climatologists predict cooling while other groups predict warming). Politicians have tried to obfuscate the matter while spending your money, by changing the terminology. The costs remain high.

The Energy Commission will respond to the Legislature's mandate sometime in 1990. The Legislature will mull it over in 1991, and probably pass some sort of legislation. We don't know who the next governor will be, so it's impossible to predict whether such legislation will be signed by the Governor. The Commission is sponsoring a conference on global warming July 30 and 31st at the University of Southern California. Commissioner Bilas has scheduled an impressive slate of qualified scientists and the last session will ask the question, "What do policy-makers do with this information?" I would urge any of you in the energy industry or in government to have someone from your office attend.

Thank you very much.

NON-UTILITY GENERATION IN CANADA: AN OVERVIEW

Presented by

A. Stephen Probyn
President
Enserve Financial Corporation
&
Canadian Environmental Energy Corporation

ENERGY AND ELECTRICITY: A CONFERENCE ON ELECTRIC POWER PLANNING IN THE 1990s

Montréal, Québec
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I am pleased to be asked to participate in this forum this afternoon. As Gerry Angevine knows, I have been a long-time supporter of the goals of CERI, even when I was working in government. Political research, as most of us know, is the habit of reading yesterday's newspapers. Political policy-making is, of course, the business of reading today's papers. Political obituaries are generally what is found in tomorrow's newspaper and are the result of political research and political policy-making.

CERI was founded by the oil and gas industry to attempt to put energy policy-making on a higher level than the Ottawa norm. At the time it was established, the National Energy Policy was dominating the headlines and the industry was in chaos. Today, after four years of rational, market-oriented policies, Canada's oil and gas industry is alive and well -- despite energy prices which are less than half the NEP prices after adjusting for inflation. Even though today's business environment is not all the industry would wish, it is continuing to plan for major exploration expenditures on such long-term projects as Arctic gas development and Hibernia, where profits are years away.

The moral of the oil and gas industry's experience for the electric power sector is that a consistent, market-driven policy environment is the key to the stimulation of investment. Given this environment, private enterprise will take risk and will put substantial capital into the development of productive capacity. These are the critical factors in determining whether the electrical utility sector will continue into the 1990s as one of Canada's priceless economic assets, or whether the sector will become yet another industrial problem which needs to be solved.

This talk is an overview of non-utility generation in Canada from the perspective of someone who makes his bread and butter in servicing that industry. I want to look, first, at the state of the industry as it exists today; and then, touch on the issues which are confronting its success. Finally, I will take a look into my crystal ball and give you my assessment of independent power's future in Canada.

First, the objective report. To date, the independent power industry in Canada is primarily an Ontario phenomenon, with important strides being made in other provinces. In Ontario, there can be no doubt that independent power is now a reality. Currently, Ontario Hydro has nearly 1,300 MW of non-utility generation or, as it's known, NUG. Of that total, 55 percent is hydraulic.

The immediate future seems to hold a big leap forward in store for the industry. In total, including projects which were brought forward prior to the issuance of the new Request for Proposals procedure announced last year, there are some 138 projects with a total capacity of 8,213 MW in the pipeline. Just to give you some perspective on those numbers, that capacity total is significantly larger than Hydro's existing hydraulic plant -- which would have a substantially lower energy output -- and represents 58 percent of hydro's existing nuclear generation capacity.

I would direct you to a number of interesting aspects of these figures. First, these are serious numbers. They are made up from serious proposals, not simply expressions of interest. Hydro has dealt with new non-utility generation or NUG through a two-stage process which involved significant expenditures of time and money for those who completed the full responses. Obviously, some the proposals are not viable. But even if only one in three of the identified megawatts is real, there are some 2,700 new megawatts in capacity out there -- nearly equivalent to the size of the Bruce B nuclear station.

Secondly, the average size of the thermal projects which has been proposed is in the neighbourhood of 100 MW. This represents -- judging by U.S. experience -- a realistic size for cogeneration projects, based on trade-offs between the economies of scale for the power plant, transmission capacity, and steam demand. So, it seems that would-be Ontario cogenerators are drawing on the experience of the American industry which has led the way.

Thirdly, these numbers are larger than those estimated by Ontario Hydro, but not unreasonably so. Hydro estimates that there is a economic potential of 6,320 MW; and that over 1,600 MW can be achieved by the year 2000. But, as Hydro itself admits, it has underestimated the potential for NUG in the past.

The province of British Columbia is also moving heavily towards independent power, although it started later and from a lower base than Ontario Hydro. Recently, B.C. Hydro announced a memorandum of understanding concerning the construction of a 55 MW waste wood unit at Williams Lake. As we sit here contemplating the future of independent power, there are other projects -- the result of the initial domestic requests for proposals --which are in an advanced state of negotiation.

Another interesting aspect of B.C.'s programme is its export sales strategy. This is being conducted by a subsidiary of B.C. Hydro, Powerex, which has been charged with developing contracts with U.S. utilities for the sale of system power. Following the negotiation of contracts, Powerex will turn to independent power generators to supply the electricity. So far, Powerex has gone to the private sector for expressions of interest in supplying power. As a result, a half-dozen proponents of thermal projects have been short-listed. The major stumbling block is still the thorny question of obtaining firm access to the Bonneville Power Authority intertie system, so as to be able to move the electrons down to California.

Other provinces are interested in independent power, although it would not be unfair to characterize their interest as somewhat academic. In Atlantic Canada, where a dependence on fossil generation means that the so-called "avoided cost" is higher than the national average, the provinces have shown varying degrees of interest.

Prince Edward Island is forging ahead with cogeneration; and the government has set up a fairly ambitious process to make it happen. New Brunswick and Nova Scotia are both interested on an individual project basis, where the private sector has the ability to provide power at a lower cost than the utility. Newfoundland also has cogeneration and independent power potential. Newfoundland Light and Power, the private sector utility, has indicated a positive response to the opportunity.

Among the prairie provinces, the response to independent power ranges from Saskatchewan which, in a depressed grain economy, has little demand for new generation of any kind; to Alberta, where the government has established policies designed to stimulate some of the small-scale renewables, particularly wind power. It's interesting to note that TransAlta, one of Alberta's major utilities, is now planning to enter the cogeneration field in Ontario in a major way. They have announced two new projects, one in Toronto and the other in Ottawa.

That was the objective outlook. Now, for the subjective side. It is looking very good from where I sit. We are on a roll and the surf is definitely up.

I belong to the Board of the Independent Power Producers Society of Ontario -- IPPSO for short -- the industry's main trade association in Canada. Three years ago, IPPSO was a group of environmentally-conscious individuals who thought that independent power would ultimately be less damaging to the eco-system than large, central generation. Now our membership includes major corporations such as General Electric, SNC, Prudential Power Funding, Westinghouse, Inter City Gas, the Bank of Montreal, the Canadian Imperial Bank of Commerce, Combustion Engineering, Chase Manhattan Bank -- and so on. Many of these companies regard IPPSO membership as a low-cost window on the industry. But to my mind, it is interesting and significant that it's a window that they would pay to look through.

Another straw in the wind is the interest of major financial institutions, both foreign and domestic, in the sector. In this context, I would like to quote from an internal report from a major Canadian bank. The report began by identifying the $3 billion+ potential for new investment by the year 2000. The report continued:

> In contrast to projects in the oil and gas energy sectors, the parallel generation market would provide "AAA" credit risks supported by long-term Ontario Hydro purchase contracts. In addition to the sizeable construction and/or take-out financing opportunities, there is much potential for high up-front fee driven project finance advisory service.

Banks tend to key into phrases like "AAA' credit" and "high up-front fee". Major banks, particularly the CIBC, Chase Manhattan, the Toronto Dominion and the Bank of Montreal, have targetted Canadian independent power. They see, like the power entrepreneurs and corporations which they serve, the significant opportunities in the sector. Although Canada's banks are certainly far from infallible, it gives me a feeling that at least there may be some economic security in numbers.

Both objectively and subjectively, the outlook for the industry is bullish, even in the bearish 90s. Beginning in Ontario and British Columbia, there are real signs of economic activity. Even in Quebec, which has historically had little interest in independent power, there are signs that some small hydro and certain other projects, which are tailored to the utiltity's needs, may get the nod.

I now turn to the issues which confront the industry's future. In general, there are two issues; and they are interrelated. The first is the nature of the economic playing field. The second concerns the way in which regulation, particularly environmental regulation, will be applied.

The most important issue that the industry has dealt with historically, is the price of the commodity which it is selling. If we reach back into our economic tool kit, we can find in the discipline of microeconomics -- i.e., market economics -- a useful description of the predicament of the independent power producer in most Canadian provinces. He or she is a vendor to a monopoly buyer or monopsonist consumer. Monopolists and monopsonists are two sides of the same coin. As the exclusive buyer of the commodity, the monopsonist who was a private utility would tend to develop a large number of suppliers who would compete with each other to provide the lowest price. His best position would be a market which was under-supplied with product, thus keeping demand up and the costs of acquiring the product from competing suppliers down. This means that only the most efficient suppliers make money. Most of them are bled for a while and then ultimately leave the industry.

When the monopsonist is a public sector utility, the rules change somewhat. There are no shareholders. Dividends to the organization essentially come in the form of a larger permanent mandate, more jobs and better-paid ones. How would we expect a public sector monopsonist to behave towards the independent power industry, based on our economic theory? First of all, the monopsonist would structure his purchase price to the private producer as low as possible. Suppliers who wanted to attract the interest of our monopsonist friend would have to find ways in which they could provide power which met the needs of his internal infrastructure -- or, in other words, his "system plan".

Let's apply the analysis to a real-life utility. Ontario Hydro is as good as any -- particularly in light of Hydro's Demand/Supply Plan Report entitled "Providing the Balance of Power", which was released earlier this year. This provides a wealth of detail on the way Hydro looks at the world. Ontario Hydro is also the focus of independent power sales in Canada. So, if you'll forgive an Ontario-centric viewpoint, I'd like to take our analysis into the world in which we live.

When one looks at Ontario Hydro through this particular lens, some interesting detail comes into focus. What are Hydro's needs? These are quite exhaustively spelled out in the Demand/Supply Report which specifies three objectives:

First, to provide continuing reliable electricity service to customers;

Secondly, to maintain low electricity costs to customers;

And thirdly, to meet environmental objectives by meeting regulations and standards and by taking a leadership role in environmental protection.

Independent power suppliers should focus on Objectives One and Three -- knowing full well that Hydro will take care of the job of making sure their price is as low as possible.

Let's look first at reliability. Currently, a major concern of Ontario Hydro is the maintenance of its capacity reserve in the 22 to 24 percent range. This figure,which is the "cushion" of generating capacity available to the system, is likely to slip to 15 percent by 1995 in Hydro's median forecast. And the situation could be far worse if the economy rebounds next year. This means that the risk of non-reliability -- brown-outs, service interruptions -- is significant. According to Hydro's pollsters, an unreliable system is political dynamite. Surveys done of the utility's shareholders -- that is, people like me who rely on Hydro's juice to keep the air conditioner on -- show that serious Hydro system reliability problems would be a major political issue in Ontario. No utility needs that.

On the other hand, most of Hydro's preferred supply options are long-term and are vulnerable to delay. The purchase of 1,000 MW of power from Manitoba's Nelson River and the next nuclear stations are the clear preferences of the utility which believes that, long-term, they meet the objectives of providing large amounts of capacity which is environmentally benign, reliable and relatively cheap. The paradox is that both nuclear power and the long transmission lines necessary for the Manitoba purchase are vulnerable to extensive delays caused by public interest groups with environmental concerns. Delay in the implementation of these projects could critically undermine Hydro's ability to maintain public confidence and hence, to secure acceptance of its strategy for achieving its objectives.

Suppliers who want to help Hydro out of this predicament (and profit by it) will come to the table with power which can be developed very quickly and meets existing environmental standards. Let's look at the NUG technologies and see how they appear from that perspective.

Small hydro is increasingly subject to environmental delays, takes a long time to build and is increasingly rare. Energy-from-waste is opposed by the Ontario Minister of the Environment and doesn't produce much energy. Exotics such as wind and solar cost a lot, are unreliable, and don't deliver significant additional capacity.

Natural gas-fired combustion turbines, however -- either in a cogeneration or combined cycle mode -- are winners. A natural gas-fired cogen plant can be up and running in less than a couple of years. Its economics are good, thanks both to the superior efficiency of the process and to significant tax incentives. In my view, Hydro will take any and all of these which meet its "avoided cost", on a priority basis. Further, it is quite likely that, if the current economic structure fails to provide sufficient revenue to generate a significant number of these projects, Hydro will find ways to enhance the economics. This may come in the form of special incentives to generators who are willing to provide peak capacity, rather than baseload energy.

This, in a nutshell, is my forecast for the non-utility generation's future in Canada. It is real; and it is natural gas.

Hydraulic developments -- which, to date, have been the industry's mainstay -- will probably play a distant second-fiddle to large industrial cogen plants. Independent power is poised to do very well. But it's not about to take over.

I do not believe that we will see significant coal-fired non-utility generation, as we have in the United States. For the time being, independent power's aspirations of emulating its U.S. big brother and becoming the major source of new electrical capacity, are unlikely to be fufilled. The Canadian utility structure is likely to remain substantially different from its U.S. counterpart where independent power -- broadly defined -- is unbundling the integrated utility structure.

Another difference from the U.S. is likely to be the composition of the industry. The really small owner/developer is likely to remain, but will not supply significant power to the grid. In Canada, tax incentives favour large energy companies and utilities are not restricted from investing in their own service area. Therefore, we are likely to see a number of utilities becoming major players in the industry. This will enable them to develop power while building an asset base of power plants -- a business which they understand -- outside their regulated entities. The recent decision by the Ontario Energy Board to insist that utilities segregate independent power and utility operations into separate companies will slow down, but will not stop this process.

In the middle, the squeeze will be on mid-sized developers. They will be forced to live by their wits, as their competitors will have the advantages of size and superior access to incentives. Those that are efficient and innovative will thrive. But woe betide any who can't come up with the innovative engineering and financing needed to survive.

Overall, in Canada, we are likely to see the independent power industry as a niche player -- playing particular roles where utilities have difficulty fulfilling their mandates. In Ontario, the industry's role is likely to be in the provision of "instant on" capacity, which is there to ensure a smooth transition to the long-term beyond the year 2000. In other provinces, the role may be to create jobs and enhance exports. Still others, may see cogen as a way of developing technologies which are out of the utility's primary area of expertise.

Being a niche player in a multi-billion dollar game could mean capital investment in non-utility generation in excess of $4 billion in Ontario -- and possibly $2 to $3 billion in the rest of the country -- by the end of the decade. The chances of going beyond that, in my view, are relatively slim.

But from my own perspective in the Canadian financial industry, which is dominated by a handful of enormous bureaucratic institutions -- let me also say that being a niche player is the rewarding way of staying in the game.

NATURAL GAS-FIRED ELECTRICITY GENERATION:
MEETING THE SHORTFALL IN THE UNITED STATES

Presented by

Paul D. Holtberg
Principal Economist
Gas Research Institute
Washington, D.C.

ENERGY AND ELECTRICITY: A CONFERENCE ON
ELECTRIC POWER PLANNING IN THE 1990S
Montreal, Quebec
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A. Introduction

The Gas Research Institute is an independent, not-for-profit organization that plans, manages, and develops financing for a cooperative research and development program for the mutual benefit of the natural gas industry and its customers.

The strategic planning and appraisal of GRI R&D programs and projects depend upon a consistent analytical framework that establishes a likely projection of future energy supply and demand and defines the probable role of the gas industry during the time frame in which the GRI R&D program is expected to have its impact. The framework that forms the scenario and data base for these planning decisions is called the baseline projection. This analysis is based on the 1989 GRI Baseline Projection and a high electricity demand sensitivity run from that projection.

The impending electric generating capacity shortfall in the United States has implications for the natural gas industry as well as for GRI. For example, a near-term requirement for new generating capacity could place gas technologies that serve cogeneration markets or central utility peak loads in an advantageous competitive position. This has implications for gas production, deliverability, and price. From a GRI R&D planning perspective, an increase in electric prices resulting from a shortfall could change the cost-benefit calculation of proposed R&D projects, increasing the estimated benefits of R&D in certain areas. As a result of these potential implications for the gas and energy marketplace, GRI has studied the potential for a generating capacity shortfall.

B. Background

It has become conventional wisdom in the U.S. that electric utilities will suffer through a tight generating capacity situation through the 1990s. As early as the 1984 projection, GRI projected regional generating capacity shortfalls beginning in the early 1990s.

The magnitude and result of the impact depends on two factors--the inevitable solution to the shortfall (which is generally the focus of discussion, for example, the potential for increased gas use, IPP generation, etc.) and the size of the shortfall. The impact and duration of the shortfall will be very different in a world with electricity demand growth of 1.5 percent then in a world with electricity demand growth of 3.5 percent. In a world with faster electricity demand growth the degree of flexibility and time to respond are shortened.

Since the early-1980s, U.S. electricity demand growth in the residential and commercial sectors has been more rapid then generally expected by forecasters. Residential electricity demand, after increasing by 1.7 percent in 1985, grew at 3.4 percent in 1986, 3.9 percent in 1987, and 5.0 percent in 1988. Growth in residential electricity demand has averaged 3.1 percent per year since 1983. Over the same period, commercial electricity demand has consistently grown at levels in excess of 3 percent per year. Growth since 1983 in commercial electricity demand has averaged 4.9 percent per year. These average rates of growth are much greater then the growth generally projected for the near term in contemporary energy projections.

To evaluate the potential impact of faster then anticipated growth in electricity demand, GRI conducted a study, the results of which will be referred to as an independent assessment, to determine the upper potential for electricity demand and generation requirements. The average rates of electricity demand growth in the residential and commercial sectors over the period from 1973 to 1988 were substituted for the projected rates of growth in the 1989 baseline projection. The residential electricity demand growth rates were set at 2.9 percent per year and the commercial rates at 3.9 percent per year. Since industrial electricity demand growth rates in the baseline projection are relatively consistent with recent history, they were left unchanged. The average rate of electricity demand growth in the independent assessment scenario was 2.9 percent per year between 1989 and 2000. This compares with growth averaging 1.9 percent per year over the same period in the 1989 baseline projection.

Figure 1 compares electricity demand growth from the 1989 baseline projection and the independent assessment.

The second element in the potential for a generating capacity shortfall is existing and planned central electric utility generating capacity. Figure 2 includes traditional cogeneration capacity. I'm defining traditional cogeneration capacity as cogeneration at industrial cites whose intent is to meet process steam and some electricity needs of the industrial user. This definition does not prohibit the sales of some electricity to utilities for distribution. However, it tries to distinguish between independent power producers and industrial cogenerators. The IPP's intent is to sell electricity. The 1989 GRI Baseline Projection shows total cogeneration capacity growing from about 25,000 megawatts in 1989 to 45,000 megawatts by 2000. By 2000 the projection assumes that 90 billion kilowatts of electricity are sold to electric utilities for redistribution by traditional cogenerators.

IPPs have been purposely excluded from the analysis at this point. This is not meant to imply that they won't be part of the solution. However, while there has been a great deal of discussion about independent power producers, substantial activity on bidding, and some firm plans, there are very few active IPP generators to date. Over the long term, GRI anticipates that the economics and structure of IPPs will likely look very similar to today's central electric utilities.

Figure 1

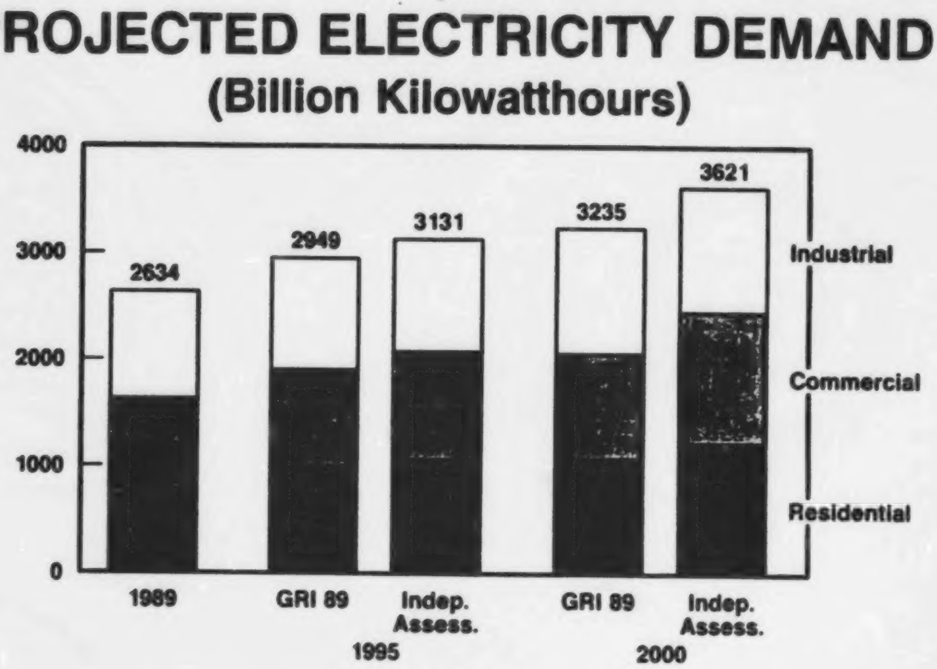
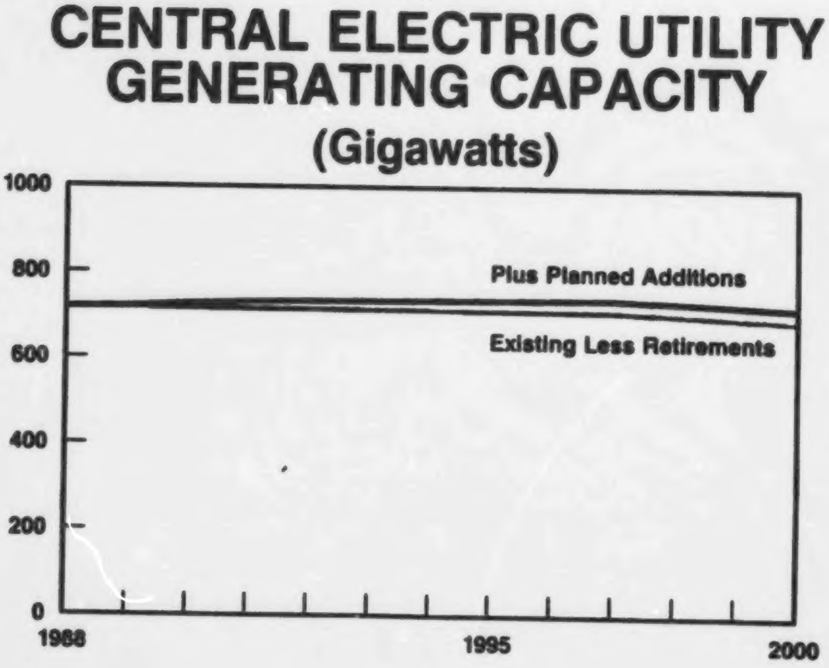


Figure 2



From the late 1960s until the early 1980s, central electric utilities added, on average, about 20,000 megawatts of new generating capacity each year. Capacity additions peaked in 1973 when central electric utilities added over 40,000 megawatts of new generating capacity. With a growing aversion toward planning additional new capacity in the late-1970s and 1980s resulting from an investment reluctance on the part of utilities and a perceived surplus of generating capacity, electric utilities have been installing a declining amount of new generating capacity in recent years. In 1985 electric utilities brought 20,400 megawatts of new capacity online. This figure dropped to 11,700 megawatts in 1986, 11,800 megawatts in 1987, and only 5,800 megawatts in 1988.

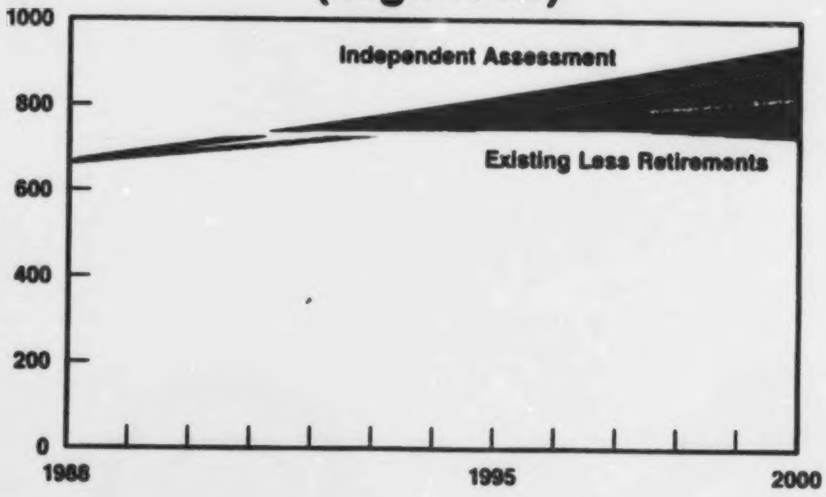
According to North American Electric Reliability Council data, current central electric utility plans include the addition of about 54,000 megawatts of new capacity over the period from 1989 to 1998. However, a great deal of this capacity is not yet under construction--over 50 percent--and it is doubtful that all of the planned capacity will actually be built, or in the case of some of the nuclear plants, completed and licensed. The baseline projection, therefore, assumes that only 30,000 megawatts of this capacity will actually be added over the period from 1989 to 2000.

Figure 3 plots the two scenarios for electricity demand growth with the projection of available central utility generating capacity. The electricity demand scenarios plotted here assume an 18 percent capacity reserve margin. It should be noted that the graph is looking at aggregate U.S. data. It says nothing about the adequacy of regional or subregional generating capacity. Regional shortfalls could occur much sooner than shown in the graph. Exceptionally warm summers or cold winters could produce problems in meeting peak requirements as early as this year in some regions.

Figure 3

AVAILABLE GENERATING CAPACITY VERSUS REQUIRED CAPACITY

(Gigawatts)



The figure illustrates that with the lower 1.9 percent per year growth in electricity demand projected in the baseline projection that aggregate electric utility generating capacity will be insufficient to meet generating requirements beginning in 1993. With the faster rate of electricity demand growth projected in the independent assessment, generating capacity shortfalls on an aggregate basis will begin to show-up in 1991.

The highlighted area in Figure 3 illustrates the area of competition between the alternatives available to meet the electric generating capacity shortfall. By the year 2000, with the baseline electricity demand growth scenario, the generating capacity shortfall will reach slightly over 100 gigawatts. Under the independent assessment scenario the shortfall will grow to over 200 gigawatts. It is important to stress that what is measured here is aggregate generating capacity adequacy. On a regional basis shortfall could be felt much sooner and could be more severe.

C. Alternatives for Dealing with the Shortfall

What are the alternatives available for meeting the needs for electric generating capacity? Table 1 lists four basic alternatives for meeting the expected generating capacity shortfall in the United States.

Table 1

ALTERNATIVES FOR MEETING CAPACITY SHORTFALL

- **Conservation/Load Management**
- **Brownouts/Blackouts**
- **Imports**
- **New Capacity**
  - **- Central Electric Utilities**
  - **- Cogeneration**
  - **- Independent Power Producers**

A major contributor to meeting or, in fact, avoiding the requirement for electric generating capacity will be load management. An active coordinated load management program involving the utilities, states, and the federal government could significantly moderate the growth in electricity demand. However, given the tightness of generating capacity today and the nearness of the expected shortfall it seems unlikely that almost any type of load management program could forestall a shortfall in generating capacity at this point in time.

A second alternative is simply brownouts or blackouts. There are obvious problems with this as a solution including political and social acceptability, economic costs (both in terms of production and damage to machinery), and system coordination issues. From the point of view of all parties this would be the least desirable solution to a generating capacity shortfall.

From a U.S. perspective, a third alternative is increased imports (largely from Canada). To the extent this is possible, however, it only helps to solve the problem in certain U.S. regions. Further, there is still some political aversion to increasing energy dependence on foreign sources, even as a friendly sources as Canada.

The most viable solution to the capacity shortfall problem is simply the provision of new generating capacity. The issues here are: who will be the provider of the new capacity, what type of capacity can be provided, and how fast. The three principal providers of new capacity will be central electric utilities, cogenerators, and independent power producers. Central utilities have recently begun to substantially increase plans for new capacity. In 1985 there were 59 turbine units on order by electric utilities with a total capacity of 4,300 megawatts. By 1989, orders for turbines had grown to approximately 200 units with a total capacity of about 19,000 megawatts.

An incremental contribution from traditional cogeneration, as defined here, should not be expected as a solution to the generating capacity shortfall. The analysis already includes substantial growth in cogeneration capacity from roughly 25,000 megawatts in 1989 to 45,000 megawatts by 2000.

The only remaining alternative to meet the expected capacity shortfall is independent power production. Using my definition, there is currently very little IPP operating experience. However, substantial bidding activity and contracting has taken place in a number of U.S. states, in particular, the state of Virginia.

Restricting the discussion to the addition of new generating capacity, either central utility or IPP, and ignoring non-purchased fuels which are limited, the choice of capacity is constrained by the lead time available. Table 2 illustrates the lead times for the construction of various types of new generating capacity as assumed in the GRI baseline projection. GRI tends to be conservative relative to some assumptions about the lead time required for new capacity. While one can argue that a particular type of capacity may take one year more or less, it is relatively obvious from the data that coal is not an option for meeting near-term capacity requirements.

The only viable options for meeting the capacity requirements in the 1990s are combustion turbines or combined cycle generating capacity. The only potential fuels for either of these types of capacity are going to be natural gas or distillate fuel oil. Residual fuel only is not an option in turbines or combined cycle units because of fuel quality issues.

Table 2

NEW GENERATING CAPACITY LEAD TIME

(Years)

	Construction	Citing & Permitting	Totals
Combustion Turbine	3	1	4
Combined Cycle	4	1	5
Large Coal	8	2	10
Medium Coal	7	2	9
Small Coal	6	2	8
Nuclear	?	?	?

D. Benefits of Natural Gas Generating Capacity

Given the higher relative cost of distillate fuel oil when compared with natural gas, gas becomes the fuel of choice for new turbine or combined cycle generating capacity. Even without the restrictions placed by the near-term requirement for capacity, gas-fired turbines or combined cycle units offer a number of distinct benefits to the central utility or IPP operator relative to other types of equipment and fuels. Table 3 summarizes the benefits from gas-fired electric generating capacity.

The major benefit in the current circumstance is the short construction lead time offered by gas-fired generating capacity. Both combustion turbines and combined cycle units can by installed in 4 to 5 years. Without permitting or citing lags (for example, by installing capacity at existing cites), capacity can be installed in as little as 2 to 3 years.

A second relative benefit is lower initial capital costs. Combustion turbines cost about $400 per KW while combined cycle units have a cost of $500 to 600 per KW. These cost compare to installed capital costs of well over $1000 per KW for all coal plants.

Gas-fired generation systems tend to be more efficient then other equipment. The combined cycle unit, for example, typically has heat rates of under 8,000 Btu per Kwh. A typical fossil fueled steam electric power plant, by comparison, has heat rates of over 10,000 Btu per Kwh.

Gas equipment tends to be more flexible then alternative systems--good part-load performance, rapid start-up, and high system availability.

Table 3

BENEFITS OF NEW GAS-FIRED GENERATING CAPACITY

- **Short Construction Lead Time**
- **Smaller Relative Capital Investment**
- **Efficient**
- **Flexible**
- **Environmentally Benign**

Last, and of growing importance, gas-fired generating capacity tends to have minimal environmental impact. Not only reduced atmospheric emissions, but also reduced water and land requirements.

D. Gas Supply Reliability

An important consideration in selecting natural gas as a fuel to generate electricity is gas supply reliability. In fact, from a electric utility perspective supply reliability may still be the most important concern (with concern about the environment rapidly catching up).

Table 4 compares several reasonably contemporary, authoritative estimates of the U.S. natural gas resource base. Despite the differences in the estimates, they all suggest that an extensive natural gas resource exists, even in the mature U.S. situation, that can be developed at rational prices. The amount constitutes about 50 years of supply at current production levels even if Canadian and other Western hemisphere supplies are ignored.

The impact of an incremental demand for gas, such as electric generation, should be thought of in the near term, not as some inherent resource cost increase, but rather as a need for increased investment in gas production. Overall, U.S. financial markets are large, and small increases in gas development investment are unlikely to be seen in direct cost impacts.

In response to a request by the FERC, GRI recently estimated the theoretical impact upon average prices for gas of an increase in demand. An increase of 1 Tcf theoretically would increase the average gas acquisition cost by about 14 to 15 cents per MMBtu. However, about half of this increase is offset by the reduced average transmission and distribution charges due to the increased volumes. The net impact on the burnertip price is an increase ranging from about 6 to 10 cents per MMBtu.

Table 4

COMPARISON OF RECENT ESTIMATES OF U.S. NATURAL GAS RESOURCES
(Tcf)

	DOE	PGC	GRI
Lower-48	1,059	832	1137
Proved Reserves	159	154	159
Inferred Reserves	108	164	149
Reserve Growth	180	N/A	N/A
Undiscovered	353	423	407
Unconventional	259	91	422
Alaska	129	152	N/A
Total U.S.	1,188	984	N/A

Looking beyond the U.S., the natural gas resource base is quite large in relation to current levels of demand. Proved reserves of natural gas, those amounts which are reasonably well known based upon drilling information, are estimated to be the energy equivalent of about 740 billion barrels of crude oil. Clearly, the natural gas resource is capable of supporting much greater levels of production.

On a note of central interest to Canadians, Canadian gas suppliers have an inherent advantage in U.S. markets when it comes to providing supplies for electricity generation. With the higher R/P ratios in Canada, it is possible for Canadian suppliers to offer the firm long-term contracts which electric utilities desire before making large long-term capital investments. U.S. gas suppliers are currently unwilling or unable to offer such long-term contracts.

E. Conclusion

In conclusion, this analysis is not advocating the exclusive use of natural gas to solve the generating capacity shortfall problem in the U.S. Table 5 translates the capacity shortfalls highlighted earlier into potential energy demand in 1995 and 2000.

Table 5

ENERGY DEMAND TO MEET GENERATION SHORTFALL

(Trillion Btu)

	GRI 89	Independent Assessment
1995	992.8	3330.4
2000	4097.1	9335.3

It is clear that with the types of electricity demand growth projected in this analysis that very large quantities of additional energy consumption will be necessary to meet future electricity demand growth. Without substantially increasing investment in the gas delivery system (including both storage and pipelines), in exploration and developement, and without the continued improvement and rationalization of the regulatory system, natural gas alone will not be able to meet the very high levels of demand suggested in this graph, particularly not the levels suggested for the year 2000 under the independent assessment.

It is clear that natural gas can make a substantial contribution to alleviating the U.S. capacity shortfall expected in the near term. However, load management, increased imports, brownouts in some regions, and an increased contribution by cogenerators using alternative fuels will also have to play a role.

THE ROLE OF NATURAL GAS IN CANADIAN ELECTRICITY GENERATION

Presented by

David Russell
Vice President, Power Generation & Projects
TransCanada PipeLines
Toronto, Ontario

ENERGY AND ELECTRICITY: A CONFERENCE ON ELECTRIC POWER PLANNING ON THE 1990'S
Montreal, Quebec
June 3-5, 1990

My remarks today were originally and somewhat deliberately entitled the *Potential role for Natural Gas in Canadian Power Generation* . Somehow the "potential" was missed in the transcription to this program, but it is an important qualifier.

Natural gas is perceived generally as a clean, reliable and secure fuel supply. Nevertheless gas is not yet playing a significant role as a fuel in the generation of power in Canada.

This is perhaps not totally surprising considering the separate evolution and competitive nature of these two branches of the energy industry. And unless the special applications for natural gas are identified and exploited, natural gas will not fill its potential as a fuel for Canadian Power Generation.

Today I intend to review the history of natural gas as a power generating fuel, TransCanada's experience as a NUG in the U.S. and Canada, the benefits and limitations of gas as a fuel and indicate the role that gas can fulfill in the power industry.

History

The use of natural gas in power generation is still coloured by some with the regulatory view expressed in the 1970's through the Fuel Use Act in the U.S. and echoed in Canada, that Natural Gas is too valuable a commodity to be used as a fuel for power generation. In the 1970's, with rapidly increasing energy prices this seemed logical especially when it was accompanied by supply inhibitions - after all, natural gas, like all fossil fuels is finite in supply.

However, it was recognized that government restrictions and regulations were contributing to the apparent supply shortfalls and high prices. Deregulation in the 1980's to allow the market to govern prices has indicated that natural gas, despite its desirable qualities, commands a burner tip price similar to other fossil fuels, especially fuel oil.

TransCanada Experience

In the early 1980's, in response to the reality of low pipeline flows and a declining gas market, we set out to find acceptable investments in new projects which would allow us to create an incremental market for natural gas. This activity is an alternate approach to straightforward marketing. This soon led us to power generation in New England.

Evaluation of the economics of a new natural gas fuelled combined cycle plant showed that it could compete favourably with a new coal fuelled plant, on an incremental cost basis, and it could dispatch economically in competition with the existing oil fuelled generating plants. I'll return to this topic later.

We knew we had found a viable project but we had to convince the Northeastern electrical utilities of this.

We were fortunate. The nuclear plant moratorium was holding back nuclear reactor construction, even causing cancellations (Seabrook 2) and slowing operational approvals (Seabrook 1).

With emerging environmental concerns, new grass roots coal plants were not gaining approval and there was a reluctance by the New England Utilities to commit to additional oil fuelled plants.

(Slide 1) In short, our proposal solved a dilemma and Ocean State Power was born - a 500 MW combined cycle power plant located in Rhode Island and fuelled by Alberta natural gas. The first phase is due for operation this fall with the second next year. TransCanada negotiated the gas supply for the project and is the majority (40%) owner. The first slide shows an artist's impression of the first Phase of 250 MW. The next two slides show the construction site in early May. Phase I is about 80% complete and Phase II about 25% complete.

(Slide 2 & 3) By the mid 1980's cogeneration was being aggressively pursued in the U.S. TransCanada decided that the Ocean State Power Project had served to overcome any market reservations towards Canadian Gas and that it would gain nothing particularly from competing in the now highly competitive market

We decided to approach the Canadian power market to determine whether the same principles applied in the U.S. would work in Canada.

Initially we approached Ontario Hydro, but they do not consider that they face the same supply option restrictions as those faced by the New England utilities. Consequently they have been more inclined to pursue their own plans and strategies.

Our approach to them and to other Canadian electrical utilities has therefore been to identify and emphasize the benefits that natural gas can provide and to propose projects that fit with their long range plans and which we believe offer mutual benefits.

(Slide 4 & 5) One result of this is a project we have recently agreed with Ontario Hydro at Nipigon, Ontario -- an enhanced combined cycle plant. The first slide shows to the technical members of the audience what we mean by this. Essentially, we build a combined cycle plant along side one of our pipeline compressor stations and use the waste heat to improve and enhance the steam cycle performance. The second slide is an artist's impression of the installation. We plan to start construction on this in a few week for operation in 1992.

Benefits

The benefits that natural gas fuelled power generation can provide are simply stated.

The benefits are in the areas of comparatively low environmental emissions, low capital cost, short approval and construction time and economically competitive power combined with a reliable and secure Canadian fuel source.

The disadvantages most often quoted to us relate to the finite resource base of natural gas, the perceived price unpredictability and, more recently, in common with all fossil fuels, carbon dioxide emissions.

Dealing with the perceived limitations first:

Gas Supply

(Slide 6) The Western Canadian Sedimentary Basin is the major source of natural gas used in Canada and as this slide shows it is basically centered in Alberta. It has a productive capacity of approximately 5 TCF annually for the next 20 years and is currently being produced at 3.5 TCFY which is forecast to grow in the near term to 4.5 TCFY as shown in this graph which is the result of a study conducted for TransCanada on the reservoir.

(Slide 7) Trillions of cubic feet of gas per year may not mean much to the power industry, but 5 TCFY converted to electricity in a combined cycle plant could provide fuel for 70,000 MW on a continuous basis.

Unfortunately only 0.5 TCFY or 7000 MW is available from the Western Canadian Sedimentary Basin for Power Generation and some of this will undoubtedly be used for other purposes. However, there should easily be sufficient gas to meet Ontario Hydro's NUG objectives.

Clearly then sufficient Natural Gas is only available to fill a small portion of the expansion plans of the Canadian Electrical Industry although it will probably be a significant proportion of any NUG projects. It will thus inevitably be used in those applications for which it is best suited - i.e. certain niche markets.

Gas Pricing

Natural gas competes in the market place with other fuels and this controls the pricing.

It is most unlikely that gas prices will become disconnected from fuel oil prices since many users (35% by volume in the U.S.) can choose to burn either.

Also natural gas competes with electricity as well as oil in the residential markets. It is not likely that a major price disconnect will occur here either.

I believe satisfactory contracts can be negotiated for pricing natural gas into the power market as we have demonstrated when contracting for our own projects.

On the other hand, natural gas has many advantages.

Environment

Natural gas combustion results in the least amount of acid gases of all the fossil fuels. It does however emit carbon dioxide as an inevitable by-product of combustion in common with all fossil fuels - but it is still the preferred fuel in this respect. When compared to potential environmental impacts relative to coal plants, the results are impressive.

The figures on this slide are reduced from a table contained in a recent Ontario Hydro report, and demonstrate clearly the clean burning characteristics of natural gas relative of various coal plants.

Lead Time

(Slide 8) Since the environmental impact of a natural gas fuelled combined cycle or cogeneration plant is well defined and limited, the regulatory approval process is comparatively simple and short.

In fact in the case of Ocean State Power, the approval process in a complicated situation of overlapping jurisdictions took 3 years. Construction is taking a further 2 years resulting in a lead time of five years.

This was longer than the four years we had projected, but still a reasonable duration.

Economics

The comparative economics which resulted in the Ocean State Power project being realized were simple and even more true today than when first reviewed by us six years ago.

At that time the likely incremental capacity in New England was considered to be a new fluidised bed coal plant - then priced at 7¢/kWh. With this benchmark, the economics of the gas fuelled plant were obvious - 3¢/kWh for the plant 2¢/kWh for pipeline transportation and thus 2¢/kWh for gas. This latter translated to an acceptable gas price and hence the project was entered into.

At these rates the plant easily competed with seasonal oil fuelled plants for economic dispatch. In fact today, especially since gas prices have fallen dramatically over the past few years, the plant will successfully compete with most of the coal fired plants in New England for economic dispatch.

Conclusions

What conclusions can we draw for natural gas in Canadian power generation?

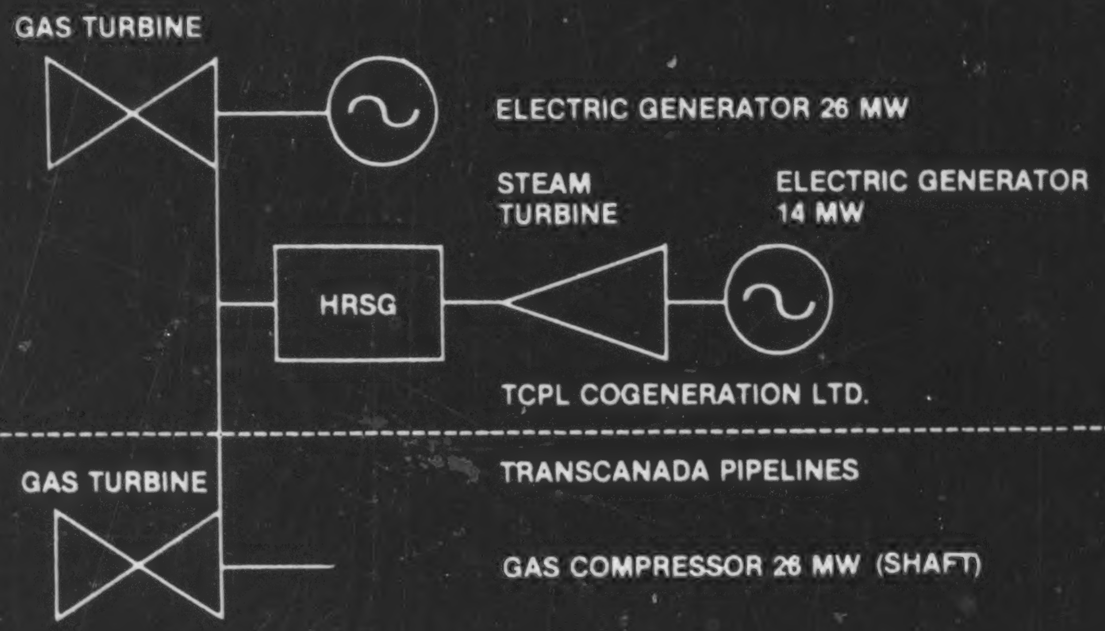
All of the advantages noted previously apply to Canadian plants fuelled by natural gas - attractive low levels of emissions, short lead times for regulatory approval and construction and even better economics for Canada than the Eastern United States, since the pipeline costs from Alberta are lower.

However, off-setting this is the fact that electricity prices are also lower in Canada -- particularly in the large markets in Quebec and Ontario with their large base of developed hydraulic power together with the nuclear program.

As I noted earlier, it is not likely that large amounts of capacity will be constructed to use natural gas, and in fact there is not sufficient gas available in Canada to fuel all the projected generating requirements of either Ontario Hydro or Hydro Quebec.

Nevertheless, I remain convinced that there are niches in the Canadian electrical expansion programmes, both for the utilities and private power generation, where short lead time plants using a secure and reliable domestic fuel source, with uncomplicated siting issues and attractive low levels of environmental impact can be of benefit.

PLANT LAYOUT



GAS TURBINE

ELECTRIC GENERATOR 26 MW

STEAM
TURBINE

ELECTRIC GENERATOR
14 MW

HRSG

TCPL COGENERATION LTD.

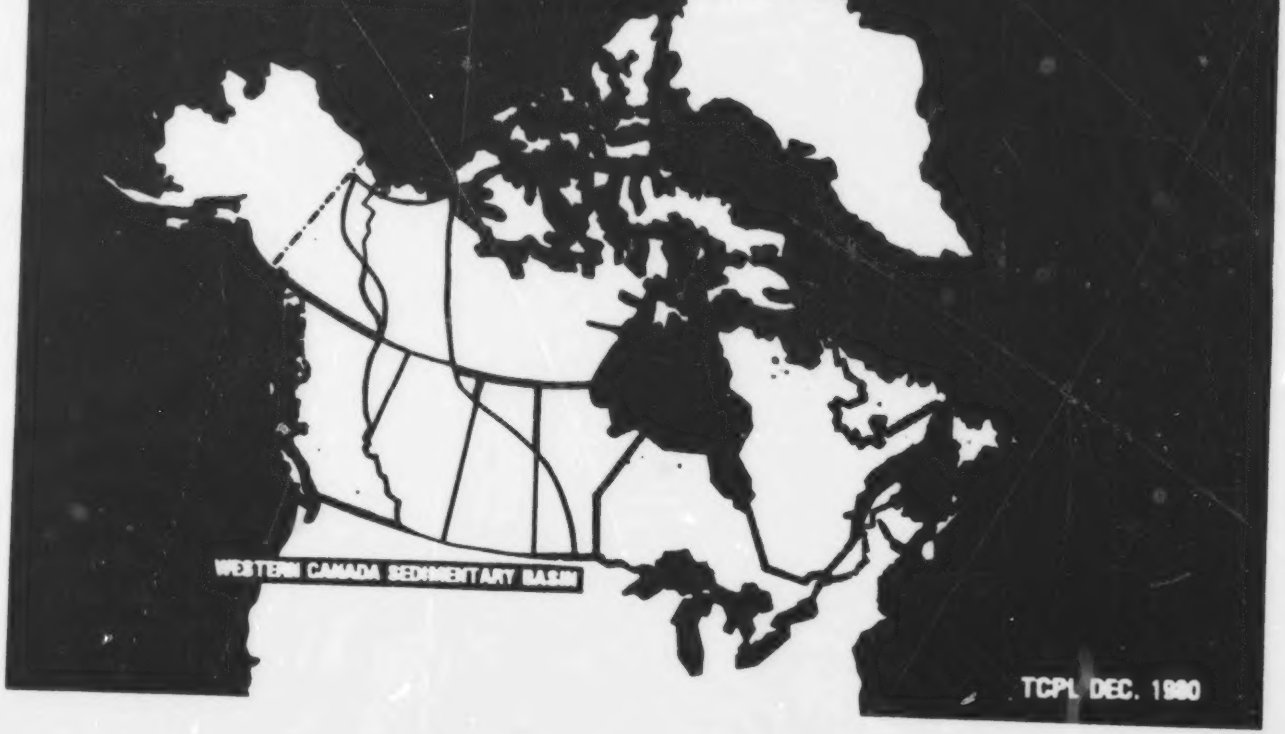
TRANSCANADA PIPELINES

GAS TURBINE

GAS COMPRESSOR 26 MW (SHAFT)

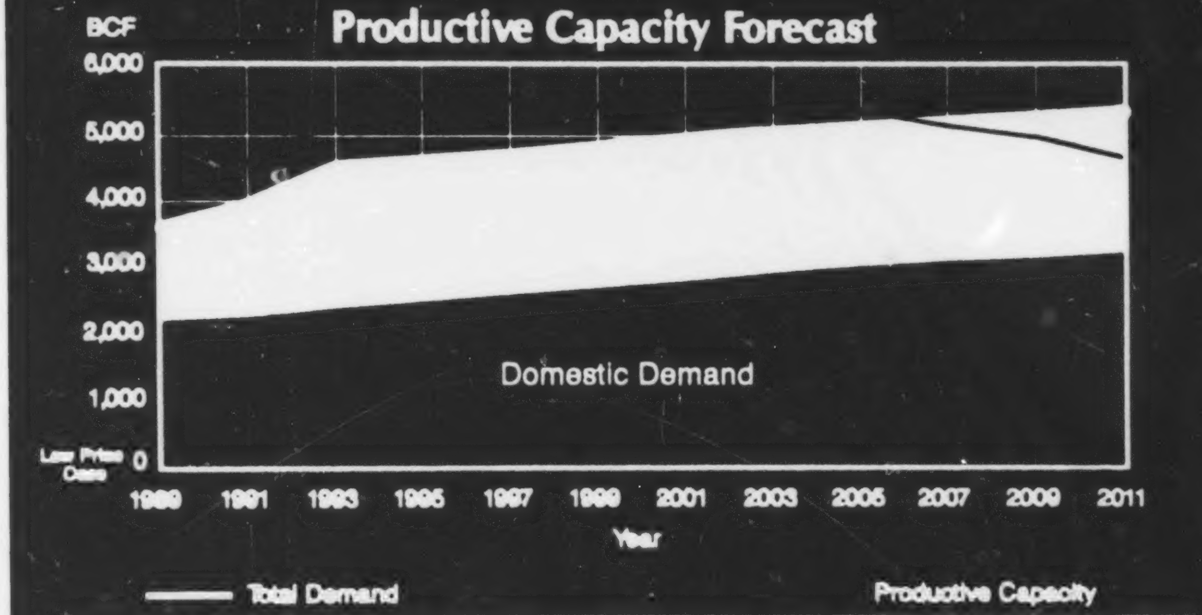
CANADA

MAJOR SEDIMENTARY BASINS

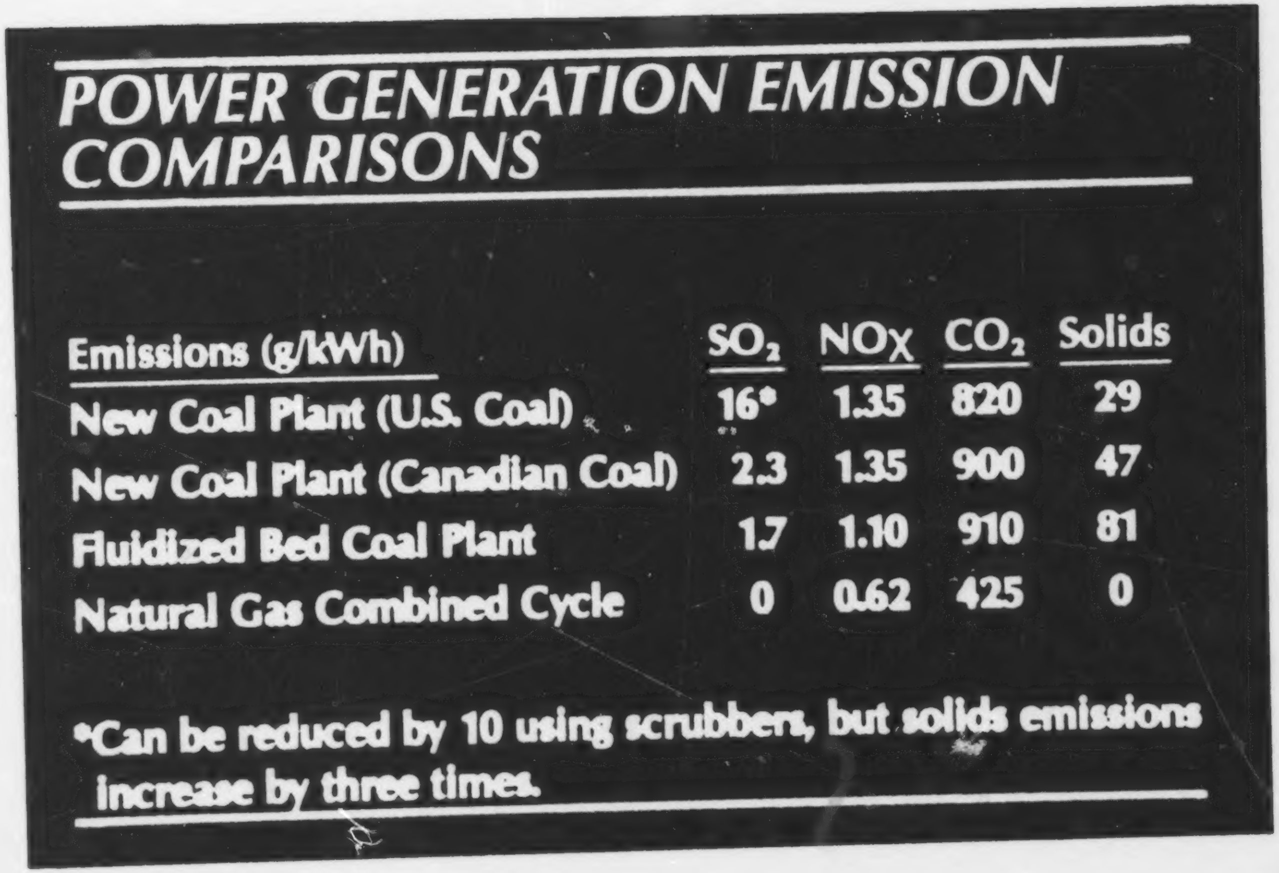

WESTERN CANADA SEDIMENTARY BASIN

TCPL DEC. 1980

WESTERN CANADA SEDIMENTARY BASIN



Productive Capacity Forecast



POWER GENERATION EMISSION COMPARISONS

Emissions (g/kWh)	SO_2	NO_X	CO_2	Solids
New Coal Plant (U.S. Coal)	16*	1.35	820	29
New Coal Plant (Canadian Coal)	2.3	1.35	900	47
Fluidized Bed Coal Plant	1.7	1.10	910	81
Natural Gas Combined Cycle	0	0.62	425	0

*Can be reduced by 10 using scrubbers, but solids emissions increase by three times.

ALTERNATIVE SOURCES OF ENERGY

WHERE IS THE FRONTIER?

Riaz Siddiqi
Electric Power Research Institute

Abstract

The United States and the rest of the world are engaged in a serious examination of the considerations that will influence the availability of reasonably priced, reliable energy, produced and utilized efficiently and in environmentally acceptable ways.

A multi-objective approach to the formulation of energy policy in the U.S., keeping in mind global implications of energy production and use will provide a dynamic and robust roadmap to the achievement of the key social objective of an increasing standard of living. Social objectives, however, must also consider impacts of energy production and consumption on the environment.

The concept we advance, therefore, is that plans for the development and utilization of alternative energy sources for the future, must start internalizing as social costs, the impact that the expected usage of these energy sources will have on the environment.

The implications of this concept are that it can alter the make, use and retrofit for environmental impact mitigation approach which tends to selectively foreclose options, to a make aud use considering environmental impact approach, which focuses the technology R & D process on the creation of options.

Electricity is a form of energy that has unique characteristics that enable it to contribute to social objectives. Furthermore, the electricity conversion process is very well suited to environmental impact management, because of cleanliness of electricity at the point of use, and centralization of waste management. Electricity's contribution to achievement of efficiency in energy end use is also well documented. It also offers benefits of diversity of primary energy sources.

The frontier, therefore, is the achievement of maximum attainable efficiencies in the production and use of electricity and the beneficial electrification of end uses to electrotechnologies that serve the twin objectives of social progress in environmentally manageable ways. EPRIs technical

divisions have identified some key examples in their respective research areas of how these objectives can be achieved.

The other frontier that needs continuous effort is Environmental Science. It is recognized globally that environmental considerations will be a key driver of energy technology R & D and commercialization. In order to ensure that energy and specifically electricity related decisions are made rationally, the state of the art of environmental science must be advanced enough to where it can proactively shape and influence energy related decisions rather than retroactively.

CANADIAN COALS, THE ENVIRONMENT AND NEW COAL TECHNOLOGIES

G.K. Lee
Combustion and Carbonization
Research Laboratory
Energy Research Laboratories

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CANADIAN COALS, THE ENVIRONMENT AND NEW COAL TECHNOLOGIES

Presented by

G.K. Lee
Chief Scientist
Combustion and Carbonization
Research Laboratory
Energy Research Laboratories
CANMET, Energy, Mines and Resources Canada
Ottawa, Ontario

ABSTRACT

Canadian energy forecasts indicate that electricity growth will increase at 2.3% per annum between 1988 and 2020 and that coal will continue to supply about 17% of the total annual electricity demand over this period. Emissions of acid rain precursors from utility coal combustion will be effectively curtailed over the next decade in response to provincial regulations and federal management plans. Advanced clean coal technologies offer the promise of more efficient electricity generation with corresponding reductions in CO_2 and power costs.

LES CHARBONS CANADIENS, L'ENVIRONNEMENT ET LES NOUVELLES TECHNOLOGIES DU CHARBON

Présenté par

G.K. Lee
Chef scientifique
Laboratoire de recherches sur
la combustion et la carbonisation
Laboratoires de recherche sur l'énergie
CANMET, Énergie, Mines et Ressources Canada
Ottawa (Ontario)

RÉSUMÉ

Les prévisions énergétiques canadiennes indiquent que la demande d'électricité augmentera au rythme de 2,3% par année entre 1988 et 2020 et que 17% environ de la demande annuelle totale d'électricité continueront d'être produits au charbon au cours de la même période. Les émissions de précurseurs de pluies acides par la combustion de charbon dans les centrales seront réduites avec efficacité dans la prochaine décennie par suite de l'adoption de réglementations par les provinces et de plans de gestion par le gouvernement fédéral. Des technologies de pointe de combustion propre du charbon promettent d'accroitre le rendement de la production de l'électricité et de réduire en proportion les émissions de CO_2 de même que les coûts de l'énergie.

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INTRODUCTION

Canadian utilities, in partnership with government, have a major responsibility in responding to the rapidly evolving environmental issues associated with electricity production in the 1990's. The necessity to use coal for electricity well into the next century will require decisive action by all concerned to effectively integrate energy planning, environmental improvement options and fiscal policies for optimal social benefit. Concerns specific to coal utilization that must be constructively addressed include global warming, acid rain fallout and waste management. In addition, the technical risks and economic uncertainties in accelerating the incorporation of unproven clean coal technologies into operational systems must be better delineated.

This paper reviews the current and forecast role of coal in Canada's electricity mix, the emission control strategies being implemented or contemplated, and the main advanced coal-to-electricity processes of potential interest to Canadian utilities.

COAL-FIRED ELECTRICITY GENERATION

Coal Supplies

In 1988 nearly 38 Mt of Canadian coal and over 8 Mt of imported coal were burned by Canadian utilities. Forecasts indicate that the total utility coal demand will escalate to 82 Mt and 110 Mt by 2005 and 2020 respectively.

Between 1988 and 2020 the domestic production of thermal coal is projected to grow at about 2.1% per annum with exports increasing from 4 Mt tonnes in 1988 to about 17 Mt in 2020. The future domestic coal supply is forecast to be slightly less than the anticipated electrical demand for coal indicating a need for new, more efficient processes for the conversion of coal to electricity as well as a gradual increase in tonnages of imported coal from 1988 levels to 18 Mt in 2020. Except Ontario, which receives all of its coal from either the United States or Western Canada, almost all of the coal currently consumed in each province is produced regionally. The range of coal properties and the amounts of coal consumed in each province in 1989 are given in Tables 1 and 2 respectively.

In general lower rank coals containing 0.2 to 0.7% sulphur - lignite in Manitoba and Saskatchewan and subbituminous in Alberta - are burned in Western Canada. Bituminous coals with sulphur contents ranging from 0.8 to 2.0% in Ontario from 2.0 to 5.0% in Nova Scotia and from 3.0 to 8.0% in New Brunswick are the norm for eastern Canada. Ontario and Alberta also consume minor quantities of lignite and bituminous coal respectively. All of the coals burned in Canada typically contain 0.8% to 1.8% nitrogen.

Electricity Demand

Canada's electrical generating capacity is expected to increase at 2.3% per annum, from 109 to 226 GW, between 1988 and 2020. Coal's share of this capacity will remain relatively constant at about 17% as shown in Table 3, whereas electricity production from all sources is projected to increase at 2.7% per annum from 485 to 1137 TWh over the same period. These forecasts indicate that coal-fired stations will be operated more intensively resulting in a decrease in surplus capacity.

Ontario, Alberta, Saskatchewan and Nova Scotia plan to rely on coal for a significant portion of their electricity production for the foreseeable future as shown in Table 4. In addition, new coal-fired generating stations are being considered in New Brunswick and British Columbia. Table 5 lists the major coal-fired generating stations in each province as well as the new capacity that has been committed or projected since 1989.

EMISSIONS ABATEMENT

Although the provinces have jurisdiction over emission controls for stationary sources, Saskatchewan, Alberta and British Columbia either have adopted or are considering the adoption of the National Emissions Guidelines for Utility Boilers advocated by Environment Canada. East of Saskatchewan, the provincial governments have set emissions caps on utility systems to achieve overall regional SO_2 reductions of 50% by 1994 using 1980 as the base year. The cap allocated to Ontario Hydro includes both NO_x and SO_2 and allows the utility the option of reducing either pollutant or both pollutants to meet its acid gas emissions target for each year.

The utility source SO_2 and NO_x emissions, nearly all of which are attributable to coal, accounted for about 22% of the SO_2 and 13% of the NO_x emitted in Canada in 1984. Tables 6 and 7 show these emissions for 1984, the 1980 base year and the projected emissions for 1994 and 2010.

SO_2 Emissions

Reductions in SO_2 emissions east of Saskatchewan are forecast to decrease by over 50% between 1980 and 2010, primarily due to control measures in Ontario. Increased coal consumption in Saskatchewan and Alberta SO_2 emissions will steadily increase over the same period, and partially offset the SO_2 reductions in Ontario and the Maritimes.

Committed reductions of SO_2 by Ontario Hydro will be achieved by electricity imports, more nuclear generation, switching to low-sulphur coal, and installation of wet scrubbers on selected units at Lambton and Nanticoke. These scrubbers will produce usable gypsum as a byproduct. New Brunswick Power will also control SO_2 emissions from the new Belledune Generating Station with a wet scrubber that will produce usable gypsum. Other SO_2 control options being studied by N.B. Power are the replacement of No. 6 oil with imported low-sulphur coal at Coleson Cove Generating Station, and the addition of an integrated gasification combined cycle plant (IGCC) at Grand Lake. Nuclear expansion and electricity imports are also being considered.

Nova Scotia plans to control SO_2 emissions through the construction of a circulating fluidized bed unit at Port Aconi which will be fuelled with high-sulphur (2.0-5.0%) coal, and by the replacement of high-sulphur coals at other stations with lower-sulphur coals. Future coal-fired plants will incorporate control strategies to meet provincial SO_2 targets.

In Western Canada the National Emissions Guidelines for SO_2 now apply only to new plants. Under these guidelines, new plants burning coals with 0.23% sulphur or less would require no SO_2 control, whereas those burning coals with higher sulphur coals would require up to 70% SO_2 removal.

NO_x Emissions

NO_x emissions in Eastern Canada are projected to decline slightly between 1984 and 1994 due to the retrofitting of low-NO_x burners at Ontario Hydro's Nanticoke Generating Station, the commissioning of the new circulating fluidized bed boiler at Port Aconi, Nova Scotia and the planned construction of an IGCC plant in New Brunswick. After 1994 the NO_x emissions are forecast to increase gradually as more coal is burned in existing and planned plants in Ontario, Nova Scotia and New Brunswick.

In Western Canada NO_x emissions will track coal consumption and increase by almost 60% from 101 kt/a to 157 kt/a between 1984 and 1994. These emissions are currently regulated in Saskatchewan and Alberta by ground-level concentration limits, although all planned and many existing plants meet the National Emissions Guidelines for NO_x.

In anticipation of more stringent NO_x emission targets by 1994 and beyond, the utility industry is actively conducting research and assessing available technology for further reducing NO_x emissions during both base load and peaking operations from installed capacity. Some of the processes under study include selective and non-selective catalytic reduction, amidogen injection, fuel reburning, staged combustion and external flue gas recirculation.

Greenhouse Gases

The major greenhouse gases attributed to coal-fired utility boilers are carbon dioxide (CO_2) and nitrous oxide (N_2O). Nitrous oxide emissions, being less than 10 ppm from existing conventional coal-fired plants in Canada, are not deemed to be a problem. However, CO_2 emissions are proportional to the carbon in coal and cannot at present be easily or economically abated.

Utility CO_2 emissions from coal, currently about 82 Mt will steadily increase to 168 Mt by 2005 unless coal demand decreases, fuel conversion to electricity increases and inexpensive processes can be found for CO_2 removal. Although these emissions levels correspond to 20% in 1988 and 28% in 2005 respectively of the Canadian total (Table 7), they comprise less than 0.6% of the world's anthropogenic CO_2 burden. Clearly, even a major reduction in Canadian CO_2 emissions will have little impact on the global build-up of greenhouse gases because of the rapid escalation of coal consumption in the centrally controlled economies and the third world over the next 25 years.

One solution would be for the industrialized countries to provide the less developed nations with expertise and technology to reduce inefficiencies in both fuel conversion and energy use. Another would be to accelerate the commercialization of advanced renewable energy sources for use in remote and tropical areas where electricity is essential but in low demand. For example, inexpensive solar or wind generators could replace small inefficient fossil-fuelled units and provide for new electricity demand.

EMERGING TECHNOLOGIES FOR COMBINED NO_x/SO_2 CONTROL

Three emerging technologies that simultaneously reduce NO_x and SO_2 emissions - fluidized bed combustion, slagging combustion and post-flame chemical injection - are being actively fostered by Canadian utilities.

Fluidized Bed Combustion (FBC)

FBC systems using either bubbling or circulating beds are on the verge of commercialization. The use of limestone as a bed material neutralizes most of the sulphur and the low combustion temperatures inherently produce low NO_x. The systems are relatively insensitive to fuel quality and have been demonstrated in small utility applications.

In Canada, the 22 MWe circulating FBC at Chatham has been successfully commissioned using 6% sulphur coal. Sulphur capture has exceeded 90% and NO_x emissions have been consistently less than 100 ppm at 3% O_2. As mentioned previously Nova Scotia Power has selected a 165 MWe circulating FBC for their new plant at Port Aconi.

Slagging Combustion

Demonstrations of the TransAlta and TRW slagging burners in a utility environment are being funded under the US Clean Coal Technology Program. Both burner designs can be economically retrofitted to existing oil and coal-fired boilers, and are ideal for firing low-ash fusion coals.

The TransAlta burner is an entrained flow reactor that fires a pulverized mixture of coal and limestone. Sulphur is captured in the slag and NO_x is controlled by multiple staging ports. Pilot-scale tests have achieved NO_x emissions of less than 100 ppm on a range of coals and sulphur captures of 70% and 80% on low-rank and bituminous coals respectively. An industrial demonstration is being conducted at Cold Lake, Alberta on a 15 MWt steam generator and engineering has started on retrofitting a 33 MWe cyclone-fired boiler at Marion Illinois with two 60 MWt LNS burners.

The TRW burner is a cyclonic combustor with staged air for NO_x control and sorbent injection at the combustor exit for SO_2 control. A 4000 h demonstration in an industrial boiler at Cleveland, Ohio yielded NO_x values of about 250 ppm with 90% sulphur capture on a 2.5% sulphur coal. Engineering for retrofitting a 70 MWe corner-fired boiler at Orange and Rockland, New York is almost complete. Trials are scheduled for 1991.

Post-Furnace Chemical Injection

The injection of an aqueous slurry containing a calcium-based sorbent to neutralize sulphur and an amidogen compound to destroy NO_x has been under investigation by Ontario Hydro. This process, called SONOX, involves injection of the slurry into flue gases from 900°C to 1200°C. In pilot plant tests, sulphur captures of up to 90% and NO_x reductions of 75-85% were achieved.

Ontario Hydro is currently seeking to commercialize the process and to develop hardware for a large-scale demonstration. Major advantages of the process are low capital cost, ease in retrofitting and applicability to all fuels.

ADVANCED CLEAN COAL UTILIZATION

Current utility combustion practice focuses on burning at atmospheric pressure. However, theoretical considerations indicate that reductions of more than 50% in CO_2 and up to 90% in acid rain precursors can be achieved by combustion at elevated pressures. These pressurized processes also allow the application of innovative combined power generation cycles that produce 16 to 45% more electricity for a given fuel input. Coupled with co-generation overall energy savings and CO_2 reductions can reach 54%.

Six advanced processes that are being developed in response to increasingly stringent emission limits for electricity generation are described below. The first two are either being demonstrated or are candidates for near-term demonstrations. The last four are still undergoing pilot-scale or large-scale component evaluations and will unlikely be demonstrated as integrated systems before 2005.

Integrated Gasification Combined Cycle (IGCC)

In this process coal is pyrolyzed with an oxidant under reducing conditions to produce a synthesis gas. Depending on the oxidant, the calorific value of this gas can vary from 3.75 to 12 MJ/m^3. As shown in Fig. 1, the hot off-gas, after being cooled prior to solvent treatment to remove gaseous and particulate contaminants, is fired in a gas turbine with steam injection for NO_x control. The turbine exhaust gas then passes through a boiler which feeds steam to a second turbine. Overall cycle efficiencies can exceed 44%.

Gasification processes using fixed-bed, fluidized bed and entrained-flow reactors have been demonstrated. However, most of the recent IGCC activities, notably the Texaco 100 MWe Cool Water Plant, the Shell 250 MWe Buggenum Plant and the Dow facility in Louisiana employ entrained flow reactors. Additional technology developments are needed to raise the efficiencies of these plants above the 38 to 41% range by increasing gas turbine inlet temperatures by 100 to 200°C, employing hot gas clean-up, raising steam temperatures by 50 to 60°C, and using air instead of oxygen as an oxidant.

IGCC processes have several features that make them particularly attractive to utilities. These include modular construction, shop fabrication of many components, phased expansion to meet capacity, reduced water demand and co-production of chemicals.

Successful commissioning of the Shell Buggenum plant will likely accelerate interest in using IGCC systems for meeting electricity growth in the late 1990's.

Pressurized Fluidized Bed Combustion (PFBC)

By pressurizing either a circulating or a bubbling fluidized bed combustor and incorporating it into a combined cycle as shown in Fig. 2, overall cycle efficiencies can be raised from 34 to 40%. Other advantages are modular construction, a 75% reduction in bed area, a 4 fourfold increase in convective heat transfer, and higher sorbent utilization. In essence, a PFBC unit operating at 12-16 bar replaces the gasifier and combustor in an IGCC process. The hot combustion gases produced are low in SO_x and NO_x, but must be filtered to ensure that the limiting ash loading to the gas turbine is not exceeded.

Three utility scale bubbling PFBC plants are scheduled for commissioning in 1990 by ASEA/Brown-Boveri. The Tidd Plant (70 MWe) and the Escratron Plant (80 MWe) in Spain produce electricity whereas the Vartan Plant (130 MWe + 224 MWt) in Sweden is a combined heat and power station.

Areas of technology risk include in-bed tube erosion, ash removal from hot combustion gases, high inlet temperatures, gas turbines and dry coal feeding.

Circulating PFBC is not as far advanced but small demonstration-scale plants are being considered in Finland and West Germany.

Topping Cycle

The British Coal Corporation is promoting a topping cycle based on partial gasification of coal with combustion of the burnable gasifier residue in a pressurized fluidized bed. As shown in Fig. 3 the hot gaseous products from both the gasifier and the PFBC are burned in a gas turbine with steam from the PFBC being used to drive a steam turbine. Owing to higher inlet gas turbine temperatures overall cycle efficiencies are in the 45% range.

This combined cycle arrangement incorporates all of the advantages and requires resolution of all of the technology risks associated with both IGCC and PFBC processes. Critical to this development is the availability of a gas turbine capable of accepting partially cleaned combustion gases at 1300°C or above.

Pressurized Flame Combustion

A number of pressurized slagging combustion concepts have been developed in conjunction with coal-fired MHD programs. Some of these including the Avco, TRW and Rockwell-TransAlta designs have been modified to perform as low NO_x/SO_x burners on conventional oil- and coal-designed boilers and could be readily adapted for use on combined cycles.

The main advantages of these combustors are compact size, modular construction, suitability for new or retrofit installations, and partial removal of ash as an inert slag. More research is needed to develop reliable systems for slag removal, hot gas clean-up and dry coal feeding.

Fuel Cells

Fuel cells have the potential for direct conversion of fuel gas to electricity via electrochemical reactions at efficiencies of up to 55%.

As illustrated in Fig. 4, a fuel cell generates electricity from a continuous supply of fuel gas to an anode and of oxidant to a cathode. The fuel ionizes at the cathode to co-produce a steady stream of electrons which generate direct current electricity to a load and a steady stream of hydrogen ions which pass through an electrolyte to a cathode where they react with an oxidant to form waste water. Waste heat, which represents the difference between the chemical energy input and the electrical energy output, must also be removed. Utilization of this waste heat by co-generation can increase the overall cycle efficiency to above 80%.

Three of the fuel cell concepts now being developed employ phosphoric acid, molten carbonate, and solid oxides as electrolytes with operating pressures up to 8 atm . The phosphoric acid cell which operates at about 200°C is the most technically advanced and has been demonstrated on cycling duty at 4.5 MWe with 40% thermal efficiency. The other two, which operate at higher temperatures, have been tested at 3 to 5 kW. Advantages of this technology are high efficiency at both full and part load, modular construction, production of hydrogen and oxygen from off-peak power for use on demand, and fast response times for peaking. More research is required to provide coal-derived gases suitable for fuel cells, to develop high reactivity electrodes for rapid, reliable fuel ionization and to increase operational life.

Magnetohydrodynamics

In magnetohydrodynamic (MHD) processes, thermal energy is converted directly to electricity by injecting electrically-conductive, high-velocity combustion gases from 2500°C to 2800°C through a magnetic field constrained in a channel as illustrated in Fig. 5. The hot gases exiting the channel pass through a radiant boiler to generate steam for bottoming the cycle and to remove slagged ash. Prior to entering the stack, the alkali seed, which is added at the combustor to render the hot gases conductive, is removed for regeneration and reuse. Overall cycle efficiencies of more than 50% are claimed for large MHD units on base load. As the unit size and the load factor decrease, the cycle efficiency decreases rapidly.

Although a gas-fired MHD topping cycle rated at 270 MWe is due for commissioning in the USSR next year, the use of coal as a feedstock has yet to be demonstrated. The US Department of Energy has funded coal-fired test facilities rated at 50 MWt to validate designs of MHD modules and at 28 MWe to evaluate seed recovery and emissions. Interest in Japan and Europe appears to be reviving after a decade of inactivity. Research breakthroughs are needed in a number of critical areas before coal-fired MHD can be demonstrated at a commercial scale. These include:

(a) high temperature air preheating
(b) seed recovery and regeneration
(c) MHD channel scale-up
(d) superconductive magnet design
(e) control of NO_x emissions and
(f) electrode reliability.

In view of the current status of MHD developments, utility applications are not anticipated before the early part of the next century.

CONCLUSIONS

In response to the forecast demand for electricity, utility coal consumption in Canada is expected to double over the next 20 years. Major environmental issues, primarily acid rain and greenhouse gas emissions, are being addressed through joint government/industry programs to demonstrate innovative control processes for use on existing units, and to accelerate the development of advanced clean coal technologies for new units.

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9. The Coal Association of Canada
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   - Electricity from Coal

Table 1 - Properties of Canadian utility coals

Rank	Moisture %	Volatile matter	Ash %	Sulphur %	Nitrogen %	HHV MJ/kg*
Lignite	26-29	18-25	7-18	0.4-0.6	1.0-1.2	15-18
Subbit	18-25	25-31	6-14	0.2-0.7	1.0-1.5	18-21
Bituminous						
- Eastern	1-10	23-37	7-26	2-8	0.8-1.7	24-34
- Western	3-9	20-35	8-12	0.2-0.4	1.1-1.3	24-36
- U.S.	1-8	28-39	4-10	1-3	1.3-2.0	26-33

* Moisture basis

Table 2 - Utility coal consumption 1989, kt

Province	Total	Domestic	Imported
Nova Scotia	2 141		
- bituminous		2 141	-
New Brunswick	705		
- bituminous		614	91
Ontario	12 809		
- bituminous		2 833	8 386
- lignite		1 590	-
Manitoba	327		
- lignite		327	-
Saskatchewan	8 534		
- lignite		8 523	
- subbituminous		11	-
Alberta	21 410		
- bituminous		577	-
- subbituminous		20 833	-
Canada	45 926	37 449	8 477

Table 3 - Coal-fired generating capacity, MW

Province	1988	2005	2020
Nova Scotia	1 052	1 952	3 152
New Brunswick	311	1 389	1 940
Ontario	9 601	11 923	16 423
Manitoba	369	369	-
Saskatchewan	1 764	2 364	2 664
Alberta	4 589	6 972	12 222
British Columbia	-	2 120	2 120
Canada	17 686	27 089	38 521

Table 4 - Electricity from coal-1988

Province	TWH from coal	Percentage of total Electricity Generated
Nova Scotia	6.1	67.8
New Brunswick	1.9	11.7
Ontario	35.0	24.5
Manitoba	0.9	5.7
Saskatchewan	9.9	76.2
Alberta	33.7	83.7
Canada - Coal	87.5	17.9
Canada - All sources	489.0	100

Table 5 - Major coal-fired generating stations

Province	MW	In Service
Nova Scotia:		
- Trenton	190	Existing
- Lingan	600	Existing
- Glace Bay	88	Existing
- Point Tupper	150	Existing
- Trenton 6	150	1991
- Port Aconi	165	1993
- New	600	2000
New Brunswick:		
- Dalhousie	200	Existing
- Grand Lake	89	Existing
- Belledune 1	450	1993
- Grand Lake 9	200	1994
- New	450	2000
Ontario:		
- Lambton	2010	Existing
- Lakeview	2285	Existing
- Nanticoke	4335	Existing
- Atikokan	215	Existing
- Thunder Bay	320	Existing
- New	2322	1995-2014
Manitoba:		
- Brandon	237	Existing
- Selkirk	132	Existing
Saskatchewan:		
- Boundary Dam	882	Existing
- Poplar River	600	Existing
- Estevan	50	Existing
- Shand 1	300	1992
- Shand 2	300	1992
- Poplar River 3	300	2010
Alberta:		
- Battle River	722	Existing
- Genessee	386	Existing
- Keephills	766	Existing
- Milner	145	Existing
- Sheerness	380	Existing
- Sundance	1990	Existing
- Wabamun	548	Existing
- Genessee 1	386	1991
- Sheerness 2	366	1990
- New	5250	1994-2010
British Columbia		
- New	2120	2005

Table 6 - Utility SO_2 emissions, kt

Year	Eastern	Western	Total	% Utility in Canada
1980	669	98	767	17
1984	720	149	869	27
1994	394	225	619	21
2010	314	287	601	21

Table 7 - Utility NO_x emissions, kt

Year	Eastern	Western	Total	% Utility in Canada
1980	158	77	235	12
1984	151	101	252	13
1994	153	157	290	15
2010	154	180	334	16

Table 8 - Utility CO_2 emissions, Mt

Year	Eastern	Western	Total	% Utility in Canada
1988	38	47	85	21
2005	79	94	173	28

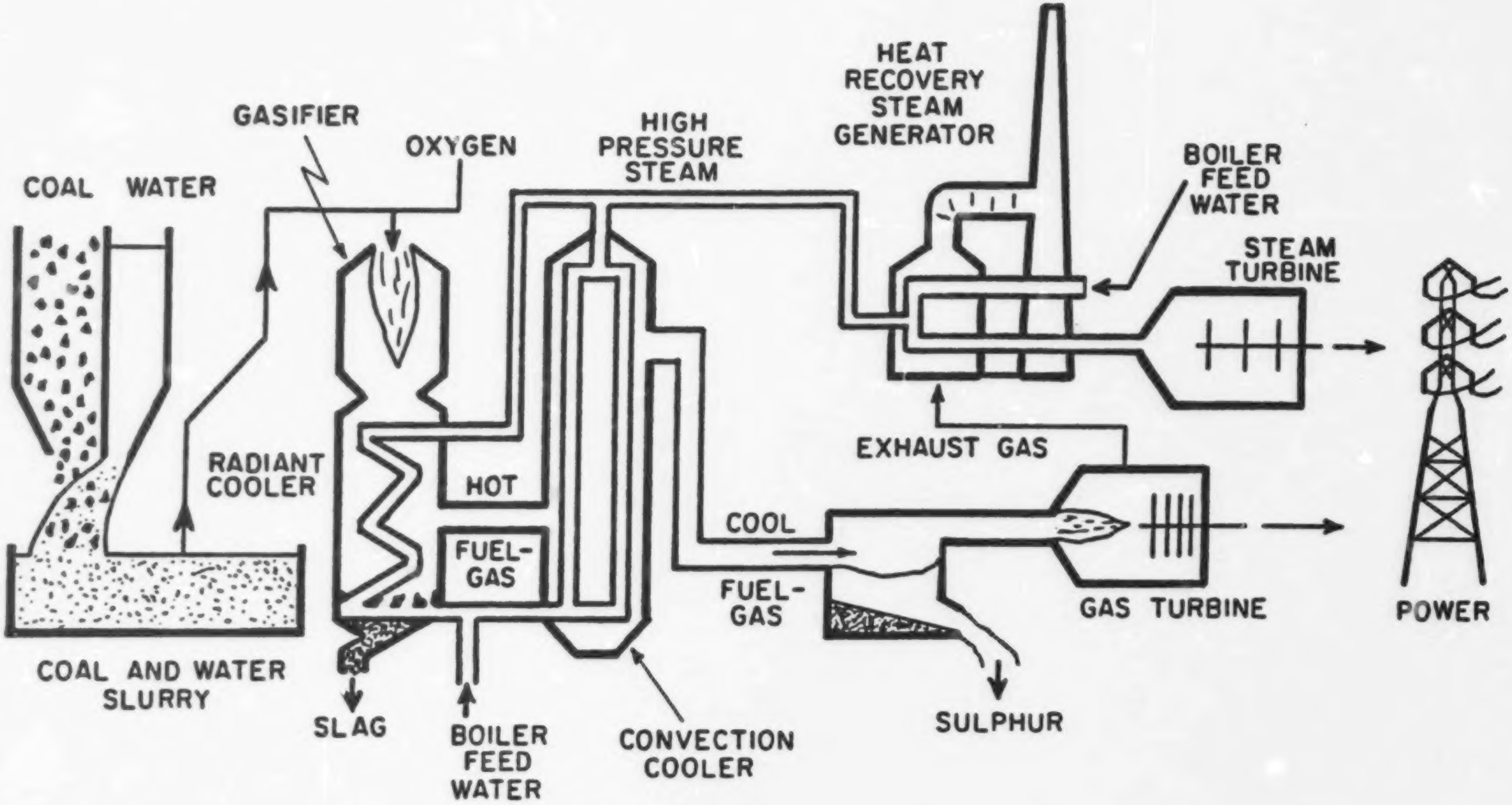
GASIFIER
COAL
WATER
OXYGEN
HIGH PRESSURE STEAM
HEAT RECOVERY STEAM GENERATOR
BOILER FEED WATER
STEAM TURBINE
RADIANT COOLER
EXHAUST GAS
HOT
COOL
FUEL-GAS
FUEL-GAS
GAS TURBINE
POWER
COAL AND WATER SLURRY
SLAG
BOILER FEED WATER
CONVECTION COOLER
SULPHUR

FIG. 1 - INTEGRATED COAL GASIFICATION COMBINED-CYCLE SYSTEM

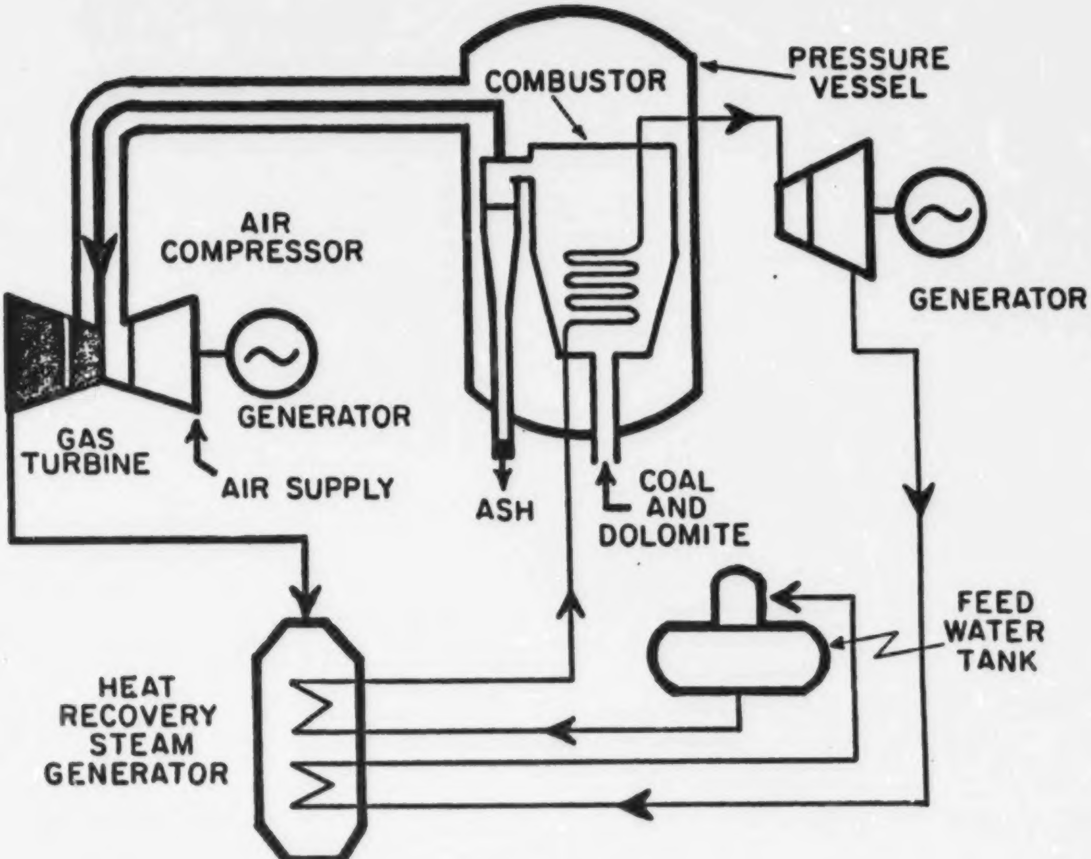
COMBUSTOR
PRESSURE VESSEL
AIR COMPRESSOR
GENERATOR
GENERATOR
GAS TURBINE
AIR SUPPLY
ASH
COAL AND DOLOMITE
FEED WATER TANK
HEAT RECOVERY STEAM GENERATOR
STACK

FIG. 2 - PFBC COMBINED CYCLE

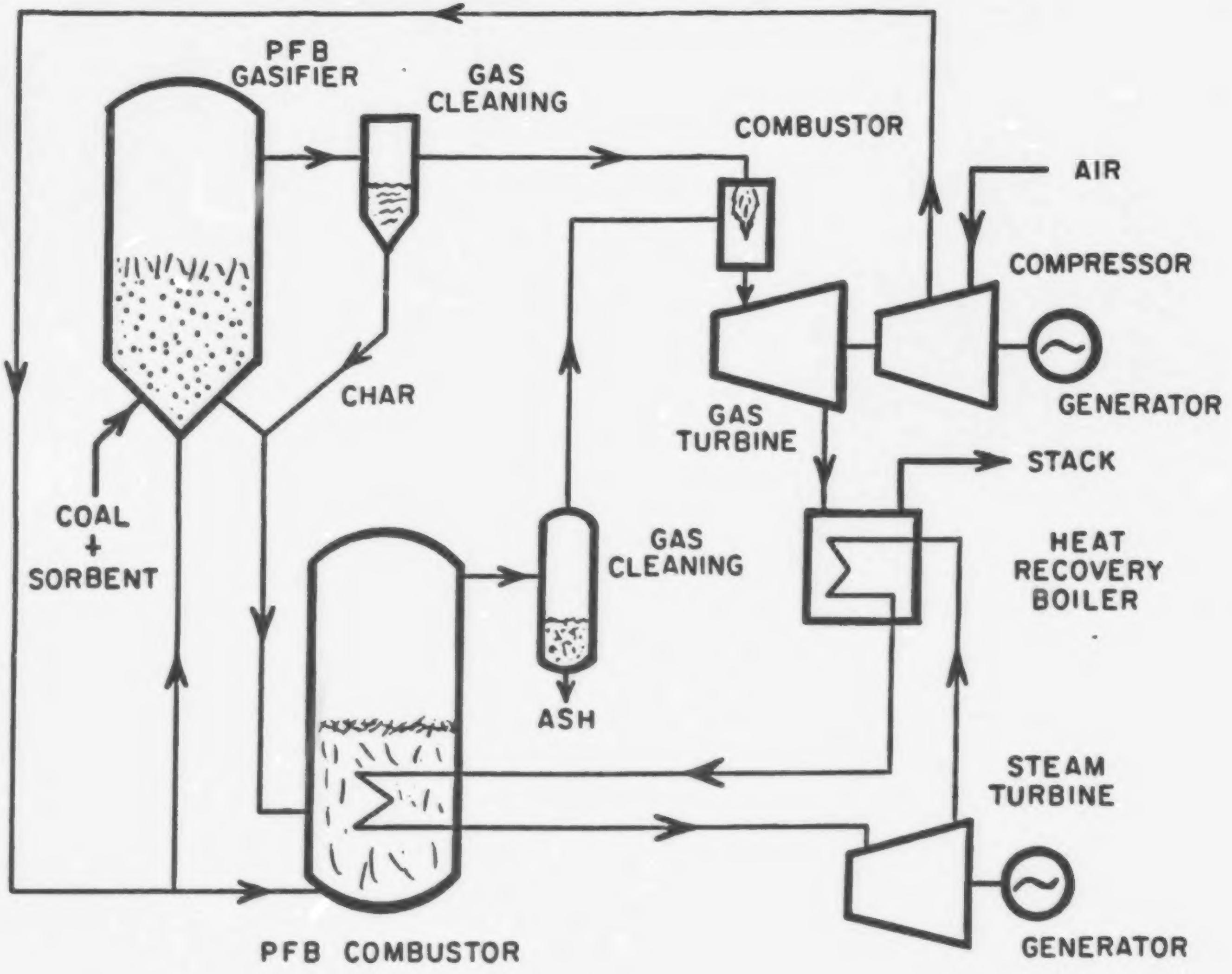
PFB GASIFIER
GAS CLEANING
COMBUSTOR
AIR
COMPRESSOR
GENERATOR
CHAR
GAS TURBINE
STACK
COAL + SORBENT
GAS CLEANING
HEAT RECOVERY BOILER
ASH
STEAM TURBINE
GENERATOR
PFB COMBUSTOR

FIG. 3 - TOPPING CYCLE BASED ON PFBC

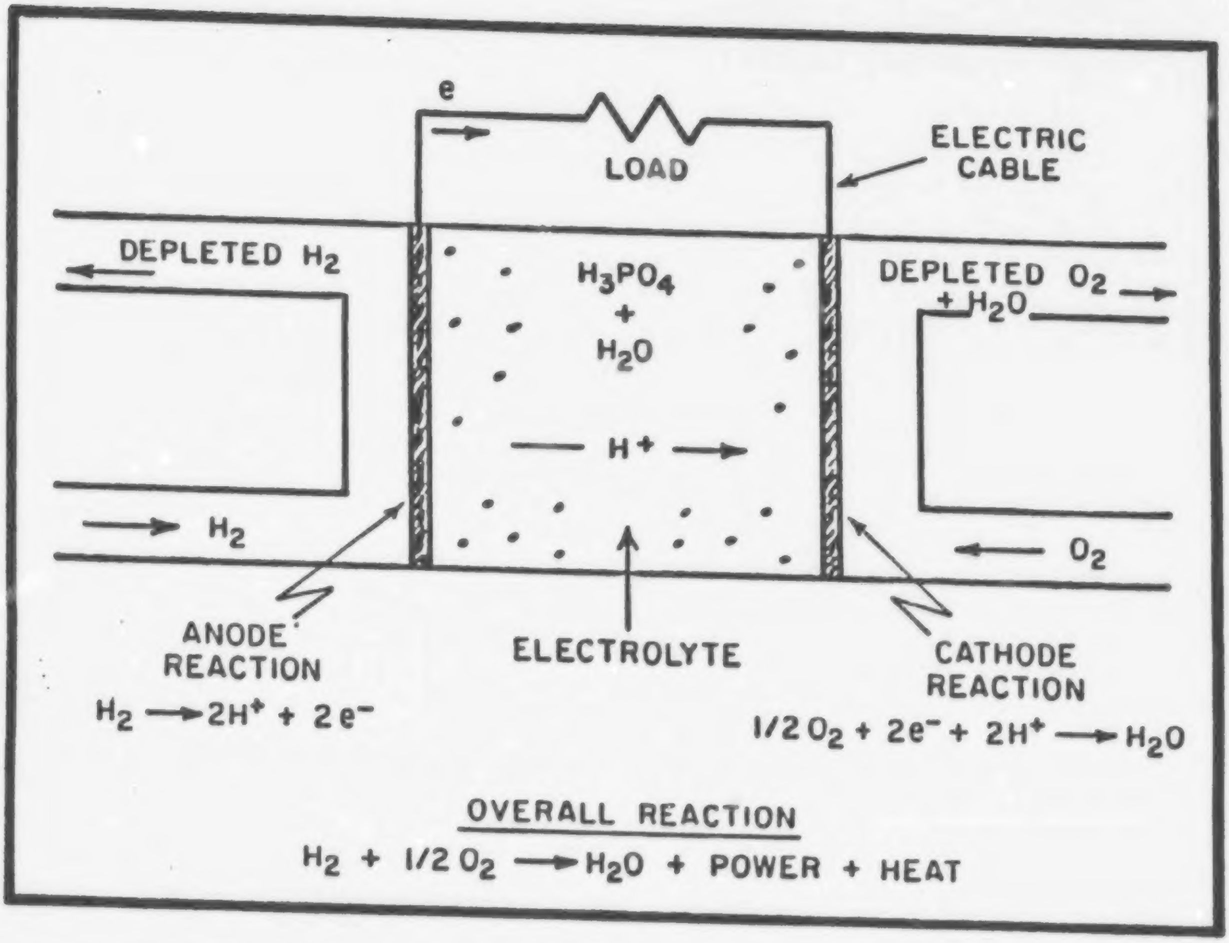
e
LOAD
ELECTRIC CABLE
DEPLETED H_2
H_3PO_4 + H_2O
DEPLETED O_2 + H_2O
H^+
H_2
O_2
ANODE REACTION
$H_2 \longrightarrow 2H^+ + 2e^-$
ELECTROLYTE
CATHODE REACTION
$1/2\,O_2 + 2e^- + 2H^+ \longrightarrow H_2O$
OVERALL REACTION
$H_2 + 1/2\,O_2 \longrightarrow H_2O$ + POWER + HEAT

FIG. 4- HYDROGEN-OXYGEN FUEL CELL PROCESS

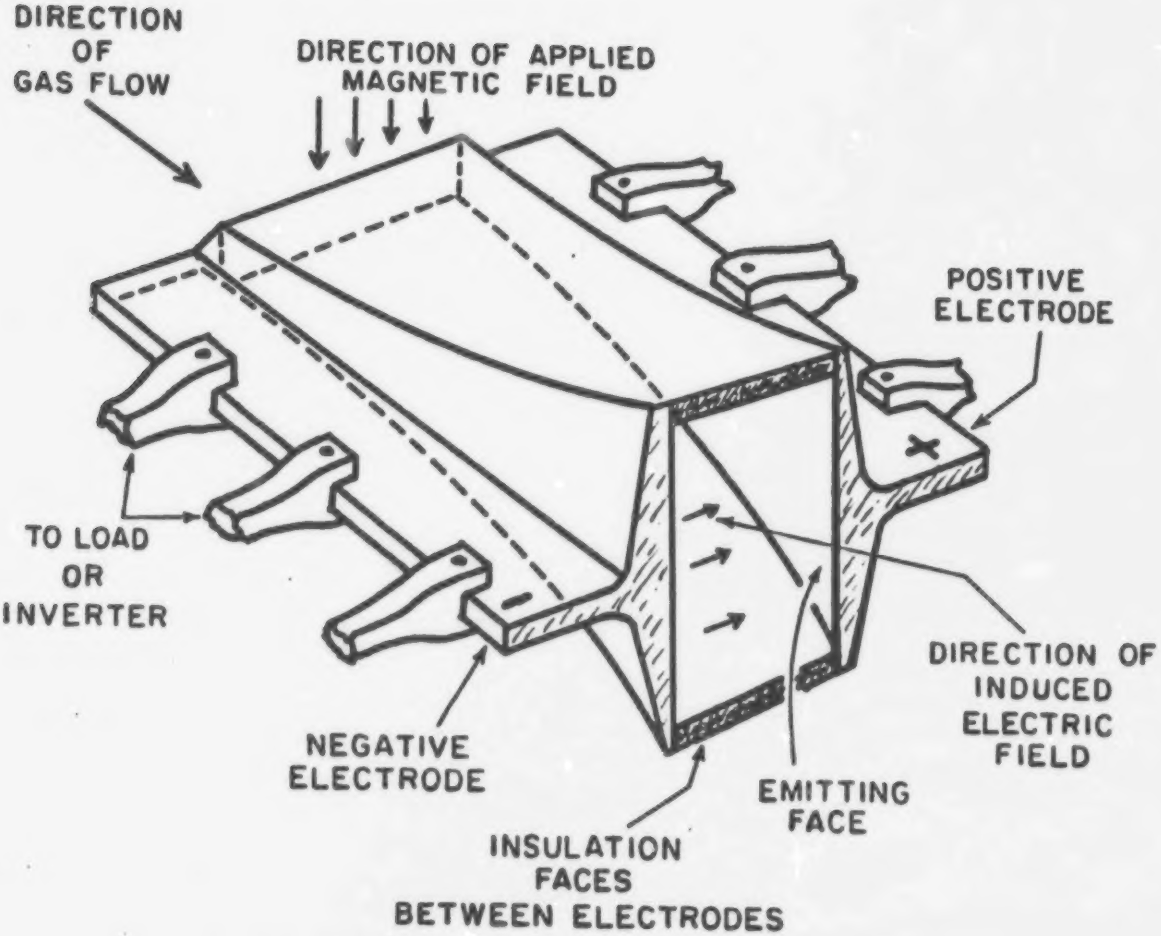
DIRECTION OF GAS FLOW
DIRECTION OF APPLIED MAGNETIC FIELD
POSITIVE ELECTRODE
+
TO LOAD OR INVERTER
−
DIRECTION OF INDUCED ELECTRIC FIELD
NEGATIVE ELECTRODE
EMITTING FACE
INSULATION FACES BETWEEN ELECTRODES

FIG. 5 - MHD GENERATOR WITH CONTINUOUS ELECTRODES

THE INTEGRATED ENERGY UTILITY:
A KEY TO ENVIRONMENTAL ENHANCEMENT

Presented by

A.C.S. HAYDEN, M. Wiggin and M.C. Hahn
CCRL/ERL/CANMET
c/o 555 Booth Street
Ottawa, Ontario K1A 0G1

ENERGY AND ELECTRICITY: A CONFERENCE ON
ELECTRIC POWER PLANNING IN THE 1990's
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Our Society is becoming increasingly aware of the environment and our effect upon it. Indeed there are demands from all sides to do something to stop the further degradation of the environment before it is too late. Global warming, acid rain, ozone depletion, local and indoor air quality, and waste disposal are all front and centre in today's newspapers, magazines and political and popular discussion, both in Canada and throughout the world.

Acid rain, due to NOx and SOx from the combustion of fossil fuels, has caused significant acidification of our lakes and rivers, decimating the fish population in many areas, and causing "die-back" of forests in Europe and in Eastern North America. Low NOx-SOx burners, fluidized bed combustion and flue gas scrubbing are developing technologies which offer solutions.

Scientists have discovered depletion and even "holes" in the stratospheric ozone layer which protects the earth from harmful ultraviolet radiation. The major cause is chlorofluorocarbons (CFC's), used in a variety of modern applications, such as propellants in spray cans and as refrigerants. Research efforts to find effective replacements are coming to fruition, with the expectation that, in the near future, no more CFC's will be produced.

Local air quality can be improved by low NOx combustion systems, reduced particulate formation from solid and liquid fuel combustion, improved transportation systems and cleaner automobile engines/fuels.

Indoor air quality, both in the home and in the workplace, is also seen to be causing increasing health effects upon people, primarily due to tightening of the building envelope and the use of certain synthetic products. Mitigation efforts are being carried out to reduce/eliminate release of combustion products indoors, to prevent use of products that release harmful chemicals (eg urea formaldehyde), and to develop improved ventilation techniques.

Municipal and industrial wastes are the source of many toxic pollutants. However, their effective disposal is becoming increasingly difficult. Landfill is being seen as only a temporary solution and can also be a significant source of methane. Advanced combustion techniques, often high intensity or fluidized bed, coupled with recycling, offer the best ways of rendering these wastes sterile, reducing the solids disposal by one to two orders of magnitude, while also recovering the significant amounts of energy inherent in many waste streams.

GLOBAL WARMING

Perhaps the most serious long term problem that we face with the environment is Global Warming, commonly known as the Greenhouse Effect. Scientists throughout the world are coming to a consensus that the earth will soon warm rapidly, due to this Greenhouse Effect, whereby heat received from the sun which was previously reradiated back out into space is being increasingly absorbed by our atmosphere, and reflected back to earth. Infrared-absorbing gases (Table 1), primarily carbon dioxide, which accounts for nearly half the effect, along with trace levels of methane, nitrous oxide and the ubiquitous CFC's, have been increasing significantly in the past 100 years, commensurate with the growth in the demand for fossil fuels. This increase in CO2, coupled to a warming trend throughout the world, has been even more remarkable in recent years, with the 1980's having the four warmest years ever recorded.

If nothing is done, it is predicted that the earth's temperature could rise an average of 2C to 5C over the next forty years, with potentially disastrous effects on climate and even sea levels. Indeed, the International Conference on the Changing Atmosphere held in Toronto in June 1988, as well as many follow-up meetings throughout the world, showed a consensus that significant climate changes could occur in the next century, due to increasing carbon dioxide and other trace gases in the atmosphere. Out of this there is an attempt to achieve a global reduction of carbon dioxide of 20%, relative to today's levels, by the year 2005.

The United States is responsible for over 20% of the world's CO2 emissions, the USSR next with just under 20%, China at 10%, and Canada at only 2%. However, on a per capita basis, Canada's CO2 production is second in the Western World, and on a GDP basis, we have the dubious distinction of being the world leader.

The complete combustion of hydrocarbon fuels results in the production of carbon dioxide and water vapour, yet our modern, industrialized society is based on energy derived from combustion.

There appears to be an inevitable growth in electricity demand, with fossil fuel-fired (coal) thermal power stations being required in many regions of Canada for a long time to come. As well, there is no widely accepted alternative to liquid transportation fuels. Alternative renewable energy sources are not sufficiently advanced technically, nor can they be introduced rapidly enough to significantly reduce the demand for fossil fuels in the foreseeable future.

WHAT CAN BE DONE TO REDUCE THE GLOBAL WARMING TREND?

Our society needs energy from fossil fuels to exist, to heat our homes and buildings, to power our cars, to fuel our industries and to generate electricity for its myriad of uses. All of these uses release carbon dioxide (CO2), the prime greenhouse gas, as a natural product of complete combustion. It may seem that we are in an insoluble dilemma. However, this is not so.

Improving the efficiency of energy use is probably the best way to reduce CO2 emissions, both from the standpoint of effective management of our energy resources and the dollar savings to the user and the country, while making the production of our goods more competitive. It is important to realize that every % of fuel saved through energy efficiency results in a like reduction in the amount of CO2 produced.

Adoption in the marketplace of much of the energy conservation R&D carried out in Canada and elsewhere over the past ten years has already resulted in significant reductions in CO2 and other greenhouse gases over what otherwise would have been emitted, due to the increased efficiency of energy use.

An even greater number of strategies, techniques, and technologies to reduce greenhouse emissions are under development which offer the potential for major reductions in the causal greenhouse gases, especially CO2, over the next 10-20 years.

These CO2 reduction/mitigation strategies can be broken down into five basic categories: specific energy efficiency; integrated energy efficiency; fuel/source switching; CO2 trapping/stripping; and closed CO2 cycle systems (biomass combustion).

The strategy offering the greatest overall CO2 reductions, and is most applicable to the electric utilities, integrated efficiency, will now be discussed in detail.

INTEGRATED ENERGY EFFICIENCY

SPECIFIC ENERGY EFFICIENCY involves the efficiency improvement of a specific piece of energy-using equipment, such as a boiler, kiln or lighting system, by better combustion, improved heat transfer, or improved performance.

INTEGRATED ENERGY EFFICIENCY involves energy use as a system, improving not only the efficiency of the energy generator itself but also the way the energy moves, often integrating more than one use, as in district heating/cooling and energy cascades, such as combined cycles and co-generation.

A conventional thermal generation plant produces electricity at a maximum of about 38% efficiency, with 15% stack loss and 47% lost to the condenser cooling water (Figure 1). An advanced thermal power process using a combined cycle, with either IGCC (integrated gasifier combined cycle) or a PFBC (pressurized fluid bed combustion), can improve the efficiency of electricity generation to 45%, with 16% less CO2 generated (Figure 2). However, most of the energy is still lost in condenser cooling.

District heating and cooling systems, whereby a number of different buildings are heated and cooled from a central source, can be an effective way of utilizing the waste heat from thermal power stations.

Most of the existing district heating systems in Canada are located in downtown core areas, or in armed forces bases or commercial/industrial parks. These systems presently use steam as the heat transfer medium, passing through relatively poorly insulated ducts. Some of these systems could be converted to low temperature hot water for heating and ice slurries for cooling, with state-of-the-art distribution systems.

One of the largest opportunities for improvement in energy efficiency is associated with the conversion of heat to mechanical energy. Typically more than 60% of the energy used to make mechanical (or electrical) energy is lost as waste heat, either in flue gases or in the condenser cooling water.

If a district heating/cooling system is coupled to the electricity generation process in a co-generation system, to utilize the reject heat in the cooling water, the overall energy efficiency can be improved to as much as 82%, producing 54% less CO2. An even better scheme to maximize electricity production would be to couple an advanced thermal generation combined cycle (IGCC or PFBC), to the district heating/cooling application (Figure 3).

The combined production of heat and power, or cogeneration, as it is typically referred to in North America, can increase the efficiency of resource utilization and thus significantly reduce the amount of pollutants generated per useful unit of energy delivered or per unit fuel consumed. If cogeneration were widely practised, the available heat could displace enormous amounts of fossil fuels presently used for space heating and pure electricity for cooling.

Viable Projects

The success of a cogeneration project is dependent on meeting the design constraints of individual components, while simultaneously integrating the common parameters within the collective parties. The interests of each can in some cases conflict and a balanced solution is achieved by looking at the project as a whole.

Sources supply heat to a thermal transport fluid which then distributes the load. In the past, the required heat was typically steam at high temperature and pressure. Under these conditions, the generator would only be able to produce as little as 40% of the electrical output that its power-only counterpart could supply.

New technology utilizing advanced concepts are aiming at supplying hot water at 120 C (250 F), thus allowing a cogenerator to increase its electric output significantly.

The transport system connects heat source to heat load by means of pumping a thermal fluid through a network of pipelines. Cost of thermal transport system is largely dependent on difference between supply and return temperature (dT). The distributor would like to maximize dT, as this reduces the quantity of fluid that must be circulated and hence the pipe sizes (capital cost) and pumping (operational costs). This is best achieved by raising the supply temperature, which would directly conflict with the interests of a power plant seeking to maximize electrical output by providing heat at low temperatures.

The heat customer can be connected to a heat supplier by means of a heat exchanger. Maximizing the supply temperature increases heat transfer rates. This allows the end user to minimize dT, thus reducing the heat exchanger area and consequently its capital investment.

The local district heating (DH) system can have more than one of the roles mentioned above. As in the case of the transport system, it wishes to minimize distribution costs. It also assumes the interests of the end user (maximizing supply temperature) when extracting heat from the transport system.

Heat Source: Cogenerator

There are many cost factors involved when designing a cogeneration plant or retrofitting an existing plant. The following will outline the general trade off resulting from combining the production of heat and electricity and the additional economic worth of the heat produced.

Utilities have normally assumed that the revenues from heat sales could not offset the loss of revenue from decreasing electrical output. Given the new trends in DH technology towards lower temperature systems, utilities should reconsider cogeneration. It may represent a means of increasing overall revenue, as well as reducing overall emissions.

Electrical Output and Marketable Heat

Presently, electric utilities generate large amounts of thermal energy. However, the energy available is at low temperatures, typically 35 to 40 C, that can not be marketed. If higher temperatures of water or steam are desired, there is a decrease in the amount of electricity produced.

As a cogenerator, the power utility would have to raise the condensing temperature in order to generate marketable heat.

Revenue

Prices were obtained from Canadian district heating companies operating in different temperature ranges. The values varied according to the supply temperature; the higher the supply temperature, the more the companies were willing to pay. Figure 4 shows the relationship of the rising economic value of heat for higher supply temperatures, based on these values.

The price curve above was used to establish the possible increases in power plant revenue as a result of providing heat for sale. The trade off between loss of electrical revenue and gain from heat revenue is shown in Figure 5.

The total revenue curve (the highest peak curve) shows an increase in revenue as a result of cogeneration. In the case of supplying heat at 120 C, the total revenue increased by 17%.

The "Heat for DH" curve and "Electric Generation" curve indicate how much of each energy form is available, for different temperatures. At 90 C, the amount of marketable heat available jumps from zero to 1980 kJ/kg. The total energy available is 3014 kJ/kg (1980 kJ/kg of heat + 1034 kJ/kg of electricity), compared to only 1280 kJ/kg from the power-only generator. The "Electrical Revenue" curve reflects the high dollar value of electricity when compared to the "Heat Revenue" curve. The "Total Revenue Curve" is the sum of the "Electric Revenue" and "Heat Revenue" curves. There is a decrease in total revenue curve superimposed on the electricity revenue curve, until the temperature reaches 90 C. At this point, the heat produced by the utility is marketable and total revenues of power and heat sales exceed the revenue of the peak power-only sales.

The largest increase in revenue occurs when heat is supplied at 90 C. Current medium temperature systems run at 120 C. Efforts are now being directed towards reducing the temperature to between 80 and 90 C. In fact, in Sweden and Denmark, there are systems already operating in this range.

The rates for electricity and heat can have a large impact on the feasibility of a cogeneration project. A decrease in total revenue can result from high electrical rates and low heat rates. Figure 6 shows the impact of high electrical rates and low heat rates.

Thermal Transport System

The idea behind DH systems is to produce heat in bulk at large plants in an efficient cost-effective manner. Added to the cost of producing heat is the cost of distributing the heat to the consumer. The sum of the cost of both components must be less than the cost of the individual heating systems being replaced.

Distribution between heat source and consumer can be considerable, particularly if the heat is from a combined heat and power plant. The concept of transporting heat over long distances has not been looked at seriously in North America.

To date in North America, steam has been the common means to transport heat in DH lines; however, steam does not lend itself to be transported at distances much greater than 3 km. "Low temperature" hot water systems, on the other hand, can easily be transported through pipelines for a much longer range. In Denmark, heat is delivered to city centres from as far away as 40 km.

The cost of installing such a capital intensive transport system can be a major economic barrier.

The optimum hot water transport systems presently being considered, connected to a cogenerated heat source, would typically have maximum temperatures of 120 C in the supply line and 70 C in the return line. Hot water pipe sizes for such a temperature scheme would be larger than for steam or high temperature hot water (180 C), which can imply higher capital pipe costs. However, with the increasing familiarity of medium (low) temperature DH technology, and the development of new pipe and insulation materials, pipe costs for medium (low) temperature systems have decreased and become competitive.

Cost of Hot Water Transport System

The dual costs of piping and pumping are the principal factors affecting the total cost of a hot water transport system.

Cost of Piping

Capital pipe costs, expressed in terms of dollars per metre of double pipe (supply & return), are a function of pipe diameter, as shown in Figure 7. These prices are based on those experienced by the PEI Energy Corporation "Charlottetown" project in 1988 and include the material costs, civil work costs, and installation costs of a transmission system being built in a residential area. Cost can vary greatly depending on physical terrain (rock vs. earth) and the primary use of the land (city streets vs. green fields). For a given heat load, minimizing pipe diameter can reduce costs.

Cost of Pumping

The cost of pumping a given flow of water through a transport pipeline is determined by the capital cost of the pump system and the operating costs to run the pump. The quantity of flow being pumped, the velocity of that flow, and the pressure drop resulting from the frictional forces acting on the flow at the walls of the pipe all influence the pumping costs.

Pumping costs increase when minimizing the capital pipe costs by reduced diameters because of increased pressure drop through the system. The total cost of the transport system is optimized by adding the pipe and pump costs over a range of possible diameters. The total cost decreases with increasing pipe diameter, due to the large pressure drops in the smaller pipe sizes.

Velocity and Pressure Drop

Transport systems have pressure and velocity limits which must be observed when optimizing the total costs. Velocity is usually maximized, up to a value of 3.5 m/s, in order to reduce the required pipe sizes. Pressure limits for a thermal transport system based on pipe constraints must not exceed the 16 bars, while other constraints could reduce this even further.

For longer transmission distances (i.e. 20 km), the pressure drop limit is the governing parameter.

Friction reducing additives currently being developed promise up to 70% reduction in this loss, improving the ability to deliver heat and cold dramatically.

Discussion

Future thermal electric plants, including nuclear, should be planned with combined heat and power as part of the siting considerations, to ensure that the waste heat can be used effectively. Heating loads should be assembled through thermal energy networks. New buildings and central heating networks should be designed so as to use low temperature hot water, rather than steam, as the thermal energy distribution media. This will improve the efficiency of thermal energy transport, reduce significantly the distribution losses, and extend the distances over which thermal energy can be transported. Modern heat-based chilling technology should be utilized so as to permit the use of industrial or utility waste heat throughout the year. This strategy will facilitate the operation of combined heating and cooling production plants, as well as lowering the need for individual chlorofluorocarbon (CFC)-based air conditioning.

Canadian electrical utilities acknowledge the opportunities afforded through integrated energy use. However, they explain their inaction by saying that such opportunities are not in their mandate. The full realization of these benefits will not take place until the potentials are recognized and a major shift in perspective takes place, along with the development of ENERGY UTILITIES, rather than just single commodity fuel or electric utilities, as major players in Canada's energy/environment future.

Taking the transportation sector as another example, with internal combustion engines efficiencies may typically be 15% or less, due to the limit of the thermodynamic cycle, and the possibility of using the waste heat appears to be negligible. However, if the transport mode can be electrified, then standby or idling losses are avoided, and fossil fuels are converted to electricity at a central power plant where waste heat can be used, emissions controls are better and lower grade fuels can be utilized. Electrification of certain transportation systems, whereby thermodynamically-limited cycles, such as the gasoline automobile Otto cycle, is displaced, could result in CO2 reductions of over 50%, but only if the electricity is supplied by co-generation systems. This has the overall effect of raising the potential for CO2 reduction dramatically, as you remove thermodynamic barriers to improved efficiency.

Municipal solid waste (MSW) is the source of many toxic pollutants. Moreover, its effective disposal is becoming increasingly difficult and expensive. From the Global Warming perspective, "sanitary" waste landfill is one of the major sources of methane emissions, a greenhouse gas some 25 times more powerful than CO2. Advanced combustion techniques, often high intensity or fluidized bed combustion, coupled with recycling, offer the best ways of rendering these wastes sterile with no air pollution problems, eliminating the methane emissions associated with landfill, while reducing the solids disposal by one to two orders of magnitude. At the same time, the significant amounts of energy inherent in the waste streams can be utilized. Use of co-generation with district heating/cooling for such systems, and taking up the varying load with a fossil fuel, can result in overall greenhouse gas emissions being reduced dramatically.

Combining different energy sources, such as coal, biomass (wood) and waste fuels and, perhaps, even nuclear power from a Slowpoke-type reactor, in a district heating/cooling or even co-generation application could give major benefits for CO2 reduction, as well as other pollutant reductions. Condensing gas systems coupled to electric heat pumps offer another potential load management and CO2 reduction strategy, especially if the electricity is hydro-generated.

Further technology development in integrated systems technology is ongoing to optimize them and extend their application. If the quality of energy generated/supplied is mated to that required throughout the energy cascade, using availability-type analysis, potential exists reduce CO2 emissions even more.

There are many factors that affect the feasibility of a cogeneration project and a specific project would have to be evaluated before being able to determine if cogenerated heat is viable. Depending on what price the utility would be willing to provide heat at their plant gate and the distance the utility is from the load would determine whether the cost of a transport system could be absorbed in the heat sales to the end users or whether any financial incentives would be required to prompt investors.

In spite of the economic potential of cogeneration, there is need to prompt cogeneration feasibility studies. Electric utilities have mandates requiring them to be able to produce quantities of electricity above anticipated demand. Therefore, electrical penalties are viewed negatively; although there also may be a mandate to produce and sell heat where possible, utilities need to be encouraged to address this issue.

The environmental benefits can be substantial, suggesting that alternatives to conventional corporations may be required to build the long distance thermal transport systems. Thus, where transport distances are large the pay back period for investment could be extended.

Recommendations for Further Action

1. Identify existing heat sources such as thermal power stations
2. Determine whether connectable heat loads exist and whether they are suitable (eg. existing district heating systems)
3. Examine existing district heating systems to see if it is feasible to convert them to low temperature hot water systems
4. Investigate the cost and feasibility of converting existing thermal power plants to cogenerators and the cost of connecting them to the heat sinks.
5. Determine at what price power plants would be willing to provide heat
6. Encourage utilities to plan new plants as cogenerators in strategic locations (relatively close to sinks)
7. Encourage mnnicipalities to set up committees to ensure cogeneration projects are looked at seriously, especially where new housing and commercial building projects are planned.

SUMMARY

1. Integrated energy cascades, particularly co-generation, offers major vehicles for CO2 reduction and energy/$ savings, particularly when coupled with advanced design generation systems, such as the integrated gasification combined cycle (IGCC) or pressurized fluidized bed combustion (PFBC).

2. Incorporation of residential and commercial buildings in district energy networks for heating and cooling provides the heat sinks required for the large CO2 reductions, up to 54%, possible with integrated utility co-generation systems.

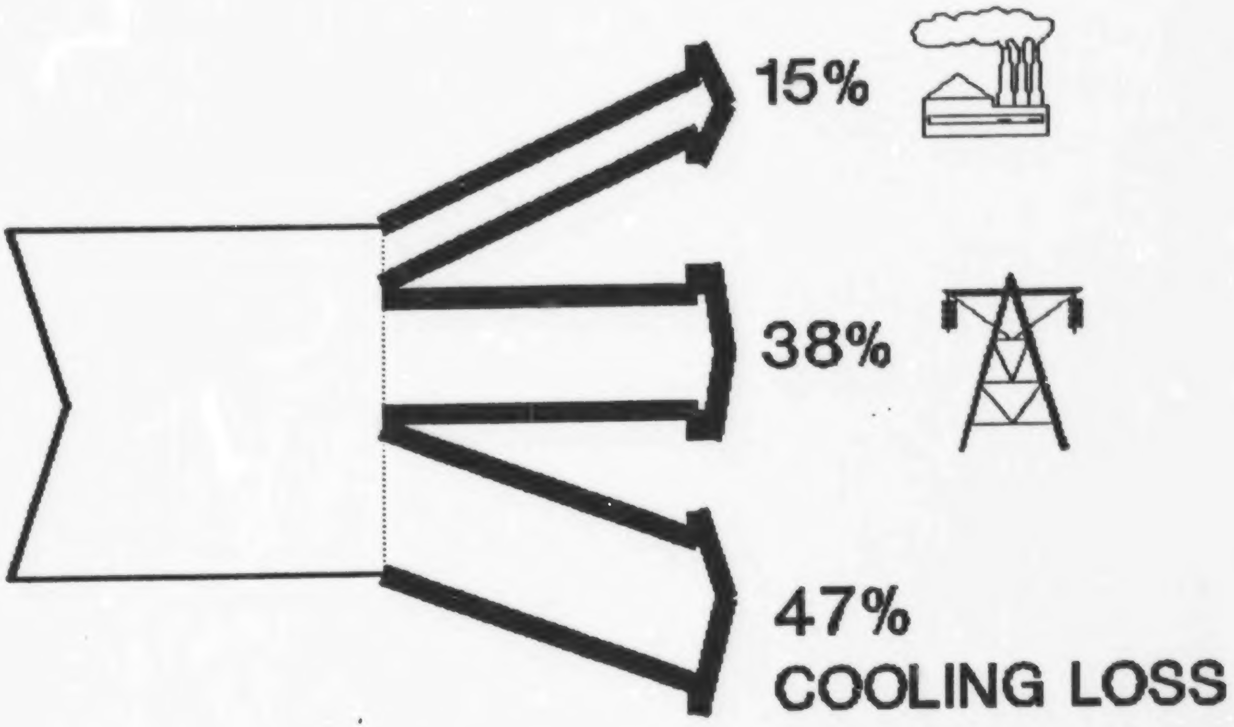
3. Integrated energy efficiency offers major opportunities for advances in energy efficiency and CO2 reduction, but a major shift in perspective is needed, along with the development of ENERGY UTILITIES, rather than just a number of competing single commodity fuel or electric utilities, as major players in Canada's energy/environment future.

4. Municipalities should be informed of the potential of cogeneration, so that they can investigate the potential for buying waste heat, and for planning systems so that heat sinks and distribution systems are available to ensure optimum utilization.

Table 1. Global Warming Causal Gases and Their Concentrations.

GAS	CONCENTRATION, ppb	CONTRIBUTION, %
CO2	345,000	49
CH4	1,650	18
N2O	301	6
CFC	0.53	14
OTHERS		13

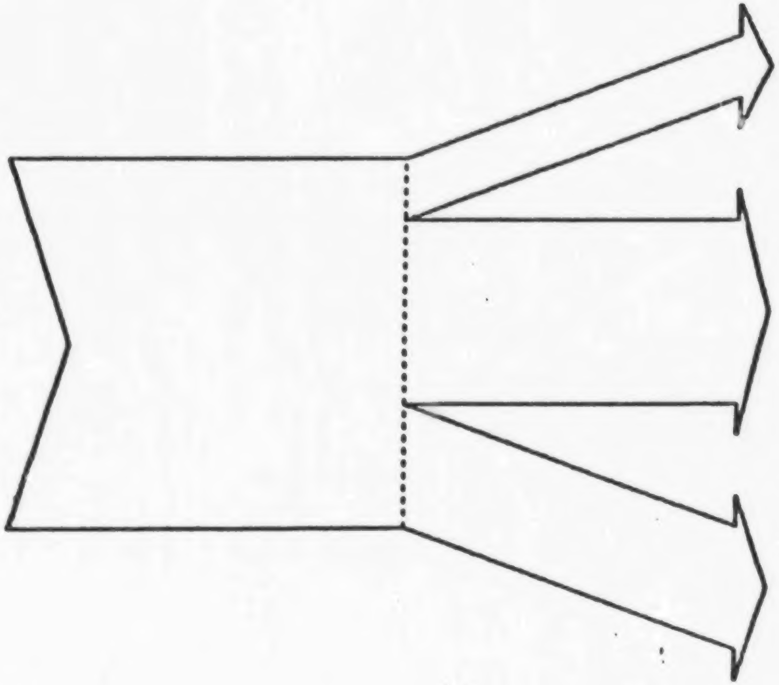
Conventional Thermal Electricity


15%
38%
47%
COOLING LOSS

Figure! . CO2 and energy flows for conventional thermal electric power generation.

Advanced Generation

COMBINED CYCLE (IGCC or PFBC)



15% STACK LOSS

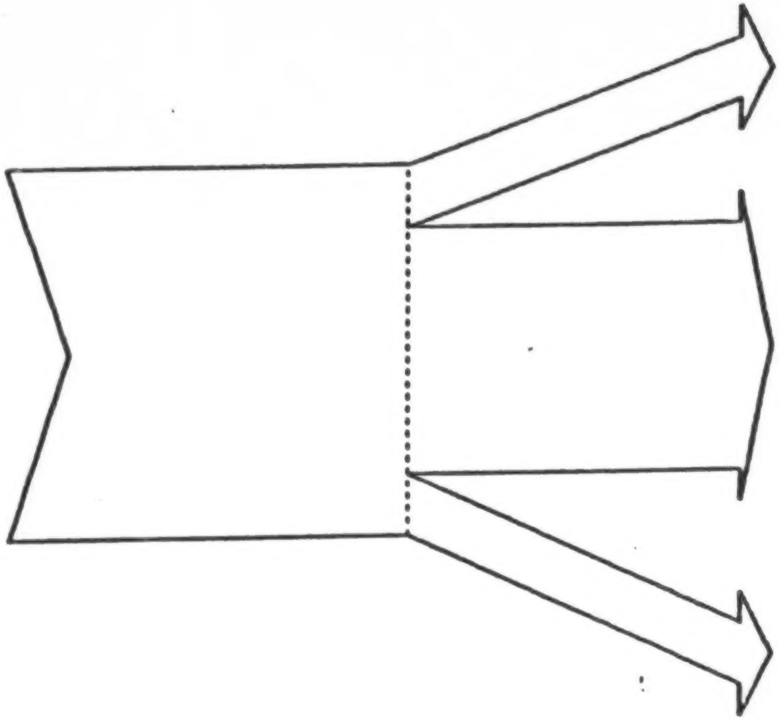
45% ELECTRICITY

40% CONDENSER
COOLING LOSS

16% Less CO2 Emitted

Figure [illegible]. . CO2 Production and energy flows for advanced electricity generation combined cycle system.

Co-Generation



13% STACK LOSS

82% ELECTRICITY
& DISTRICT HEATING

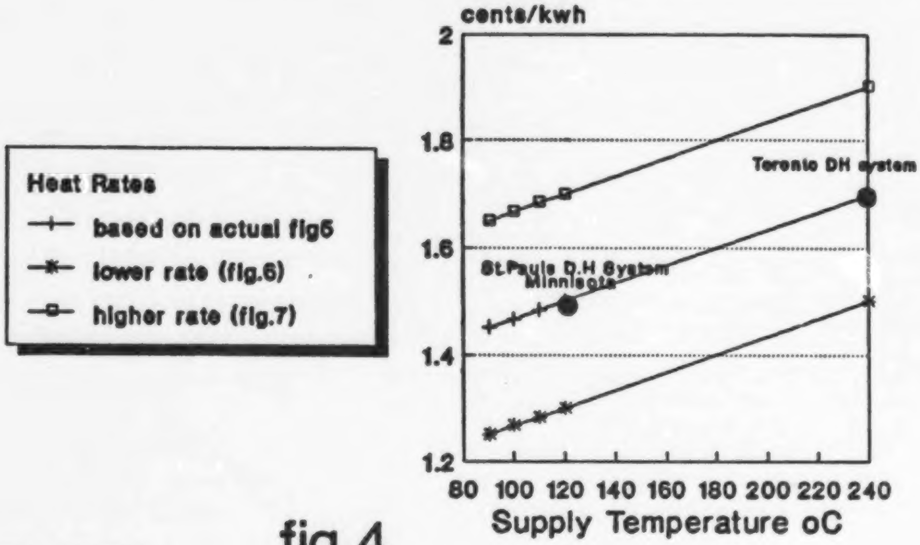
5% CONDENSER
COOLING LOSS

54% Less CO2 Emitted

Figure [illegible]. CO2 Reduction and energy flows from co-generation system.

Rates for Marketable Heat

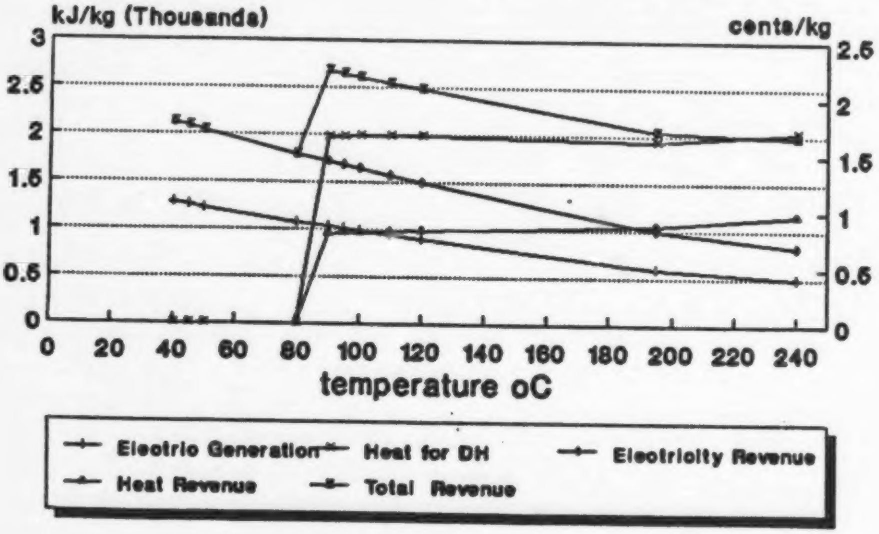
Used in fig.5, fig.6, and fig.7



1 MBtu = 294 kwh

fig.4

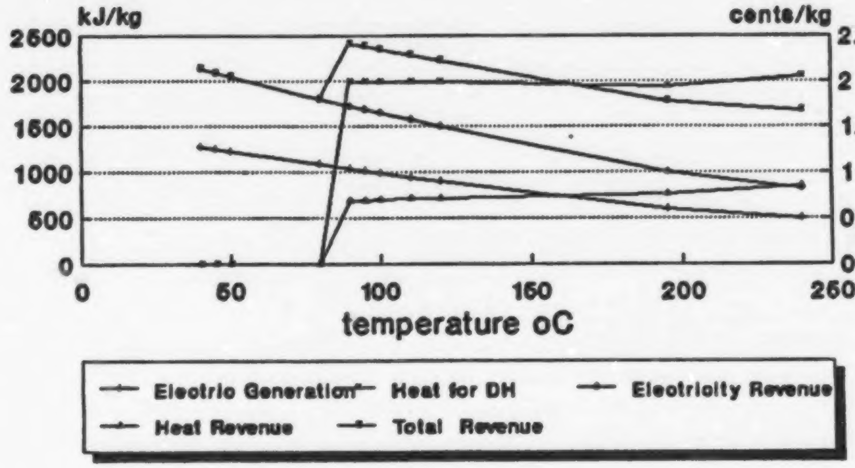
Heat and Electricity Trade Offs



based on given heatrate as shown in fig4
Elec.e 5cents/kwh high rate:conservative
estimate.$/kgsteam initially 560oC,20MPa

fig.5

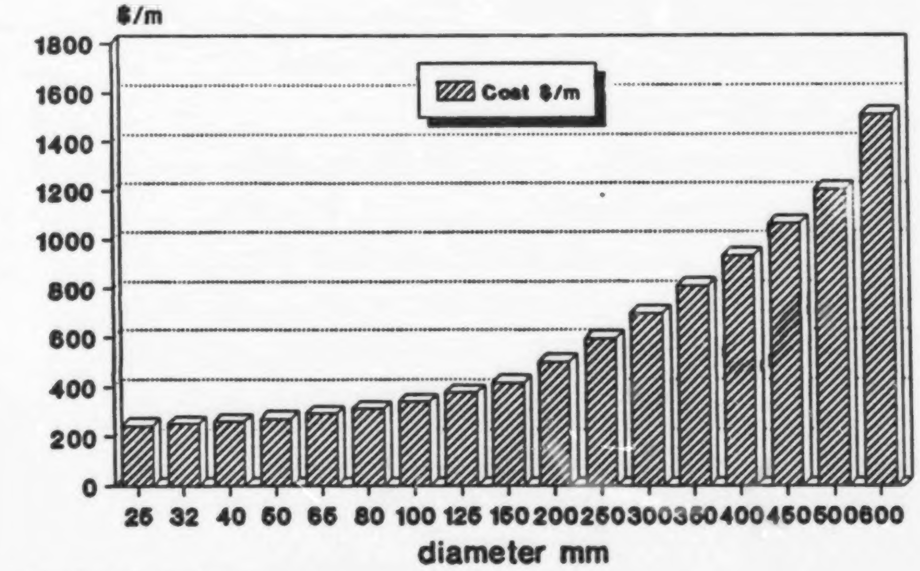
Heat and Electricity Trade Offs
Low Heat Rate and High Electrical Rate



Low heat rate as shown in fig.4
Electricity @ 6 cents/kwh
$/kg of steam initially at 550oC, 20MPa

fig.6

Cost vs. Pipe Diameter



Based on PEI Energy Corporation
Charlottetown project costs.

fig. 7

THE NUCLEAR OPTION : PROSPECTS AND PERSPECTIVES

Presented by

Yoshinori Tatsuta
Senior Nuclear Power Planner/Economist
The International Atomic Energy Agency
Vienna, Austria

ENERGY AND ELECTRICITY: A CONFERENCE ON
ELECTRIC POWER PLANNING IN THE 1990s
Montreal, Quebec
June 3-5, 1990

Nuclear power is continuously making strides in meeting the World's increasing demand for electricity.

Today nuclear power gives about 5 % of the World's energy and 17% of its electricity - a little less than that of hydro power.

Nuclear power is not a single solution against the 3E (energy, electricity and environment) problems but the use of nuclear power can be one important element in the world energy supply mix.

This paper discusses the nuclear power option with its prospects and perspectives, focusing on topical issues of global warming, waste management, public awareness, future direction of new generation reactors and safety, concluding with the discussion on the role of nuclear power as a continuing challenge for the future.

Introduction

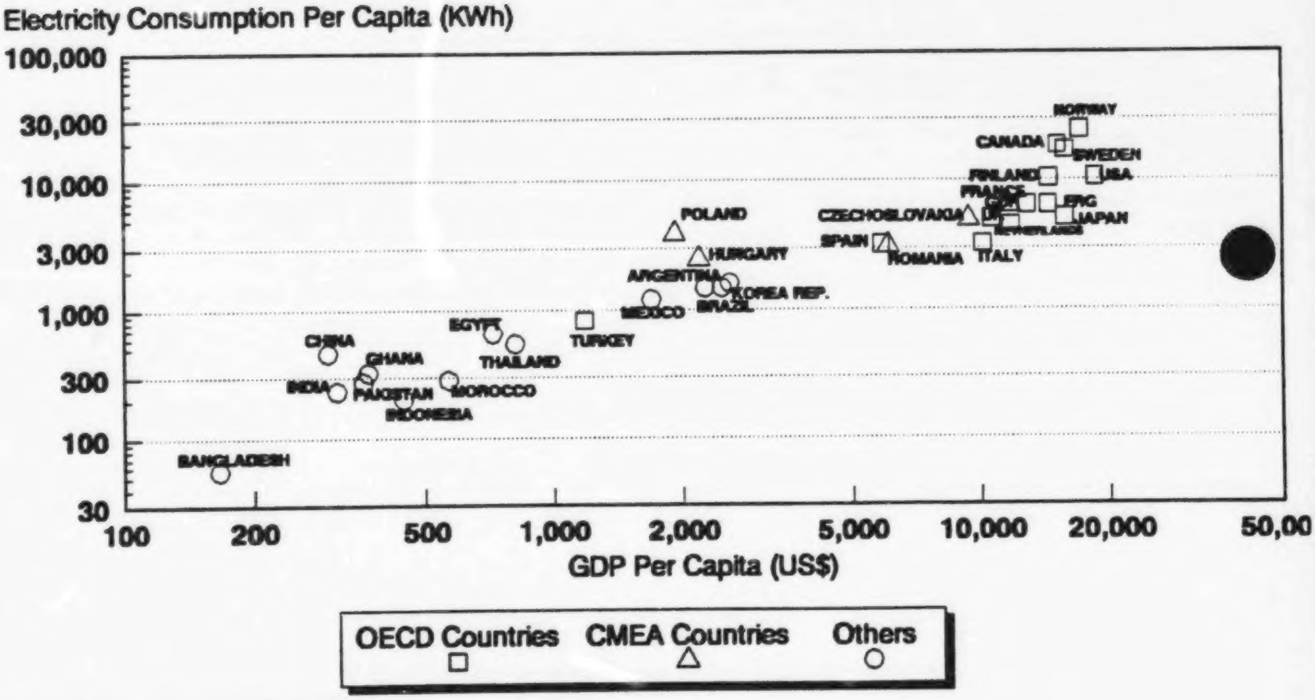
The increasing use of energy has led to industrialization, improved transportation, increased productivity and improved standards of living. The strong demand in electricity is to be seen in the flexibility of this energy form in satisfying the demand of users for energy services. At present, the generation of electricity acounts for approximately one third of the world energy use. In 1970, 1.6% of world electricity was generated by 81 operating nuclear power reactors; in 1989, 16.8 % of electricity was generated by 426 operating reactors.

Yet during the 1980's, nuclear power became less attractive to many countries. The accidents at Three Mile Island in 1979 and at Chernobyl in 1986 increased concerns about safety. Long delays in licensing and commisioning occured. Construction and operating costs escalated. Cancellation of orders for nuclear power plants and haltation of the constructions occured in some countries. In the United States, the biggest share holder in the nuclear world, no new application for a new nuclear power plant has been filed since 1978.

Although the political and psychological consequences of the Chernobyl accident remain substantial, projections of electricity demand suggest that nuclear power will remain an irreplaceable element in the global energy supply mix. Electricity has become a key feature in energy policies in many countries and it is clear that it will assume growing importance in supplying energy in the future.

World Energy and Electricity Demands and Supply

Energy is the lifeblood of our societies. An enormous increase in the use of oil, coal, gas and hydropower has been a major means of raising the standard of living in many countries. There has been a clear relationship between the level of economic development and energy consumption with enormous difference among industrialized and developing countries. (Fig. 1)



IAEA EEDB and the World Bank Atlas

Fig. 1. Electricity consumption per capita vs. GDP per capita (1987)

Even after the oil shocks, the OECD countries with one sixth of the world's population consume almost half of the world's primary energy and more of electricity, and the developing countries with three-fourth of the world's population just consume some 30 % of the world's primary energy and 20 % of the world's electricity. (Fig. 2)

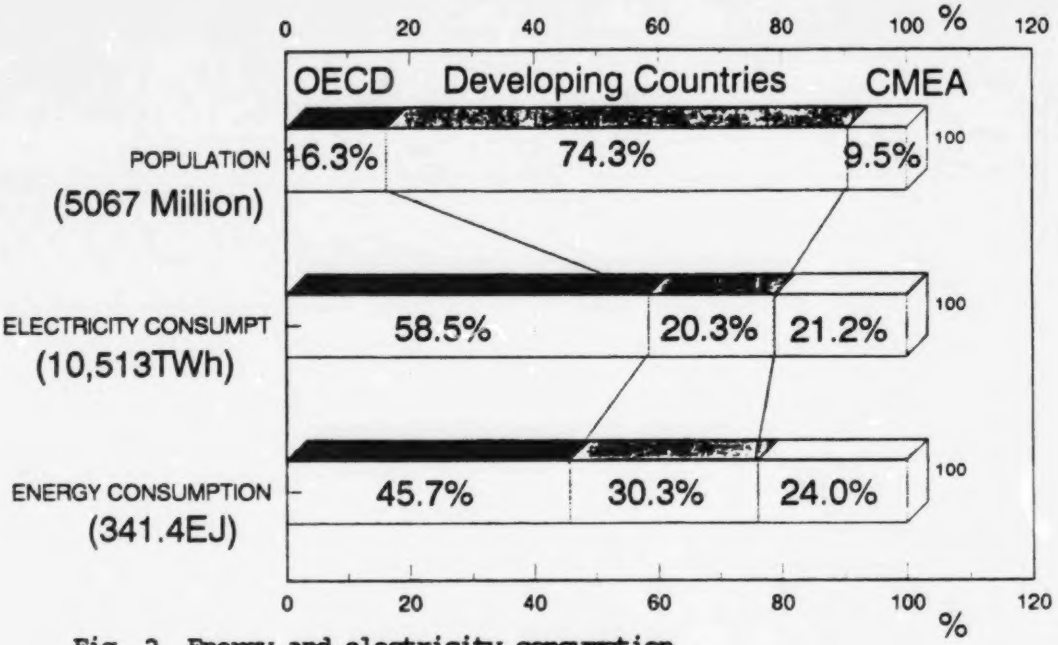


Fig. 2. Energy and electricity consumption vs. population distribution (1988)

In developing countries, in spite of the serious economic problems which many of them have encountered since the oil shocks, their use of both primary energy and electricity has continued to expand at a rate of 4 to 6 % per year. They simply have tremendous needs for energy to develop their economies. (Table. 1)

Table 1. World energy demand outlook

(annual average growth rate %)

Year / Country Group	1969 → 1973 [First Oil Shock]	1973 ⟶ 1979 [Second Oil Shock]	1979 ⟶ 1986	1986 → 1988 [Oil Price Declining]
OECD countries	4.2	1.1	-0.3	2.8
Developing Countries (South East Asia)	6.3 (11.1)	5.9 (8.0)	4.3 (4.2)	5.7 (10.7)
Socialist countries	5.8	4.8	2.2	3.1
Total World	4.8	2.8	1.1	3.3

(Source: BP Statistical Review of World Energy, July 1989)

The oil shocks in 1973 and 1979 changed what had until then been a steady trend in the OECD countries towards ever increasing energy use, and the use of electricity, while the primary energy consumption stagnated, continued to rise - although at a slowed rate - in an almost one-to-one relationship with GDP. Developing countries show a much higher electricity growth rate than that of industrialized countries.

It seems very likely that the future availability and use of electricity will turn out to be a determining factor for development. Electricity has great flexibility in use and can be controlled with precision to provide heat or power at any time in the amount needed, whether for residential, industrial or commercial uses.

It can be easily predicted that the global demand for more energy, particularly electricity, will increase in future.(Table 2)

Table 2. World energy/electricity demand

Year	1988	1995	2000	2005	2020
Primary Energy (1000 Mtoe)					
World Total					
IEA(1989.6)		9.2		11.8	
IAEA(1989.7)	8.2	9.2-9.7	10.0-10.9	10.6-11.9	
WEC(1989.9)			9.5-10.3		11.6-13.5
Developing Countries					
IEA(1989.6)		1.9		2.8	
IAEA(1989.7)	2.5	2.9-3.1	3.3-3.7	3.6-4.2	
WEC(1989.9)			3.4-3.6		4.9-5.8
Electricity (1000TWh)					
World Total					
IAEA(1989.7)	10.5	13.4-14.5	15.7-17.7	18.0-21.1	
Developing Countries					
IAEA(1989.7)	2.1	3.4-3.5	4.4-4.9	5.4-6.5	

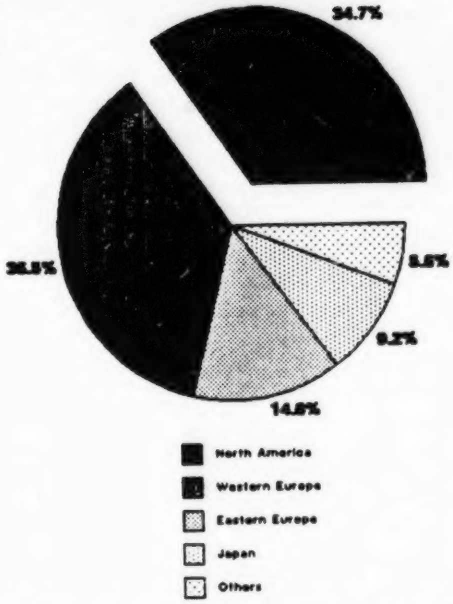
Nuclear Power - Current Status

Today 26 countries, whose populations total more than 2 billion, benefit from nuclear electricity. In addition, other four countries with more than 1 billion people, i.e. China, Cuba, Iran and Romania, have their first nuclear power plants under construction.

At the end of 1989, 426 nuclear reactors were connected to electricity supply networks, with a total installed net nuclear capacity of about 318 GWe, accounting for about 5,200 reactor years of operating experience. There were also 96 nuclear reactors under construction totalling nearly 79 GWe, mostly in the USSR(22 GWE), France(12 GWe), Japan(11 GWe), Czechoslovakia(5 GWe), USA (4 GWe), and Canada(4 GWe).

Figure 3. shows the percentage distribution by country of the world's installed nuclear generating capacity as of 31 December 1989. In this achievement, states belonging to the Organization of Economic Cooperation and Development (OECD) accounted for 256,113 MWe, corresponding to 80.5% of world capacity in 1989, while states belonging to the Council for Mutual Economic Assistance (CMEA) contributed 43,826 MWe, corresponding to 13.8%. Developing countries contributed 18,332 MWe at 5.7% of world share.

OECD COUNTRIES	80.5%
USA	30.9%
FRANCE	16.5%
JAPAN	9.2%
GERMANY,FED.REP.	7.1%
CANADA	3.8%
UNITED KINGDOM	3.5%
SWEDEN	3.1%
SPAIN	2.4%
BELGIUM	1.7%
SWITZERLAND	0.9%
FINLAND	0.7%
ITALY	0.4%
NETHERLANDS	0.2%



CMEA COUNTRIES	13.8%
USSR	10.8%
CZECHOSLOVAKIA	1.1%
BULGARIA	0.8%
GERMAN, DEMO.REP.	0.7%
HUNGARY	0.5%

OTHERS (incl.Taiwan,China)	5.7%
KOREA,REP.OF	2.3%
SOUTH AFRICA	0.6%
INDIA	0.4%
ARGENTINA	0.3%
MEXICO	0.2%
YUGOSLAVIA	0.2%
BRAZIL	0.2%
PAKISTAN	0.1%

Fig. 3. Percentage distribution by country of the world's installed nuclear generating capacity

In energy terms, nuclear power plants generated about 1,854.5 TWh of electricity during 1989, an increase of 3.3 % over 1988, and accounted for about 16.8 % of the world's electricity production.

Figure 4. shows a historical development of nuclear electricity generation and its contribution to total electricity production since 1960. After more than 30 years of development, nuclear power is today providing a sizeable portion of the world's electricity. In the period since the first oil shock in 1973, nuclear based electricity production sixfolded.

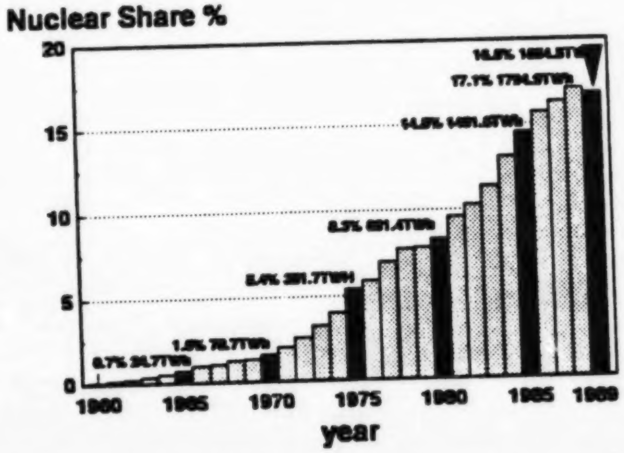


Fig. 4. Nuclear electricity generation and share of total electricity generation for 1960 - 1989

Nuclear power now provides 17 % of the world's electricity and 5 % of its primary energy. The importance of nuclear power is, however, very different in different countries (Fig. 5). France is the world leader with 75 % of its electricity coming from nuclear power and exported surplus electricity of some 38 TWh to its neighbours in 1988. Belgium gets 61 % of its electricity from nuclear plants, Republic of Korea 50 %, and Sweden 45 %. There are now 10 countries which get more than 30 % of their electric energy from nuclear power. Of the Eastern European countries, Hungary at present has the highest fraction of nuclear generated electricity at 50 %.

The worldwide evolution of nuclear power is continuing with the general trends prevailing these days. In 1989, 12 reactors were connected to the electricity supply networks increasing the world nuclear power capacity by 10.4 GWe. In the period since the Chernobyl accident, although stagnated situation of nuclear power progmamme covered many countries, some 60 GWe have been built up to contribute to the world electric power sector.

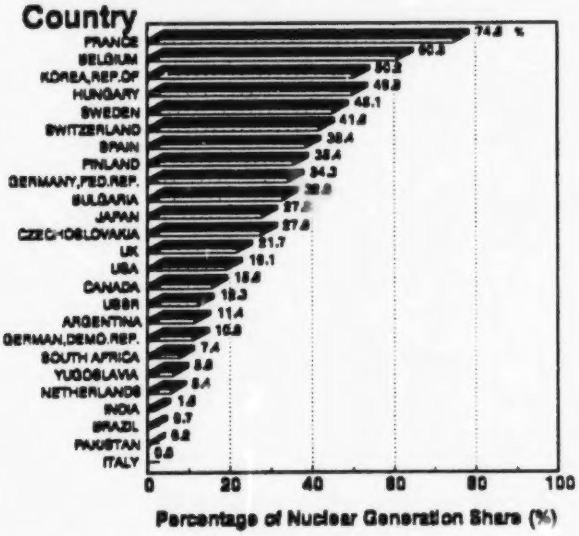


Fig. 5. Nuclear share in the electricity production in 1989

Future outlook of nuclear power:

The current outlook toward the year 2005 is published in the IAEA Reference Data Series NO. 1 "Energy, Electricity and Nuclear Power Estimates for the period up to 2005" (July 1989 version). The review for 1990 version is underway and results are expected for July this year.

Nuclear generating capacity up to 1995 will be largely determined by past decisions, although it can still be affected by construction or licensing delays or by policy changes. The situation after 1995 is covered with some uncertainties. Figure 6. shows the projected growth of installed nuclear generating capacity up to the year 2005, based on IAEA growth estimates. The world nuclear generating capacity is expected to increase from 311 GWe in 1988 to 488 GWe in 2005, corresponding to an average annual growth of 2.7% in this period.

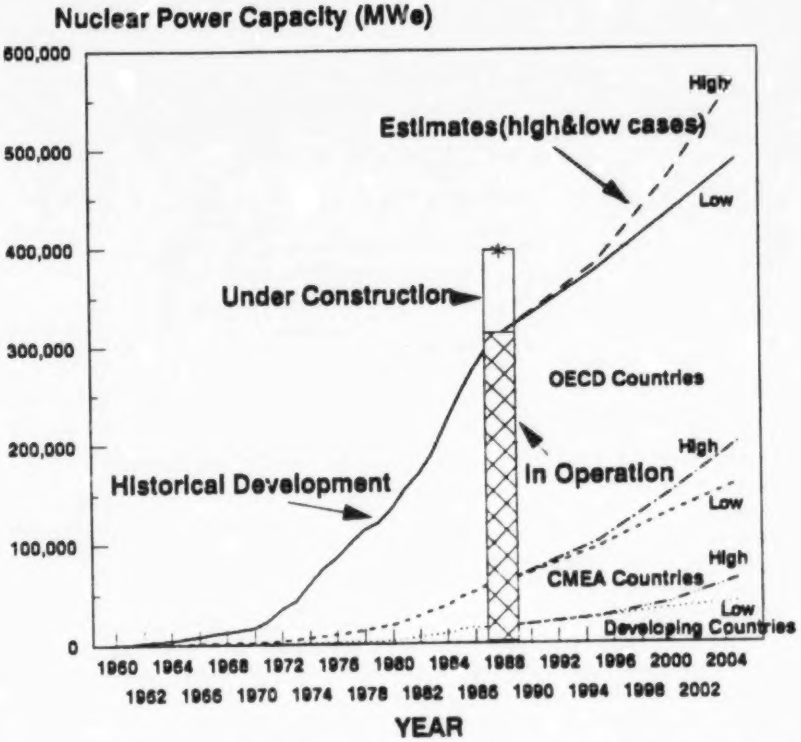


Fig. 6. Projected growth in nuclear generating capacity up to 2005

The projected growth in nuclear electricity generation and shares of total electricity generation up to the year 2005 are also shown in Figure 7. The data are based on IAEA low growth estimates. The world's nuclear electricity generation is projected to increase from 1,795 TWh in 1988 to 3,097 TWh by the year 2005, corresponding to an average annual growth of 3.3%. The contribution of nuclear electricity to the world's electricity generation is expected to stay at about 17% up to 2005.

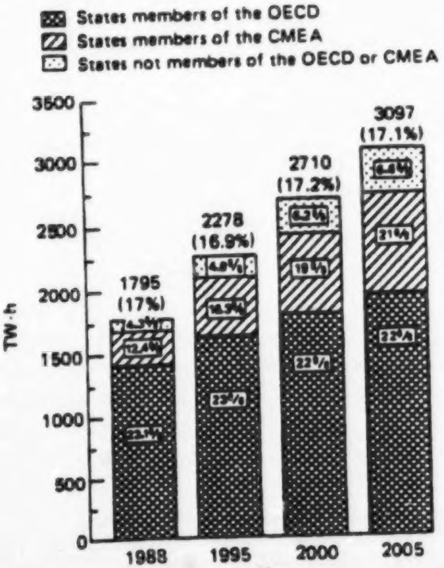


Fig. 7 Projected growth in nuclear electricity generation up to 2005 and nuclear shares of total electricity generation (based on IAEA low growth estimates)

Future Prospects for Nuclear Power

Building up of the nuclear contribution is continuing, however, the future prospects for nuclear power appear very uncertain at the moment. In Sweden,the phasing out of nuclear power by 2010 was decided and the Government announced that the first two plant shutdowns are to take place in 1995 and 1996, reducing the present line up from 12 to 10. However, recently discussion has arisen whether phasing out is feasible. Big discussions on different aspects of the energy question are going on in this country.

The present nuclear outlook is bleak in several countries. In Italy even the existing nuclear power plants are no longer in use following the referendum. Switzerland, the Federal Republic of Germany, Belgium and the Netherlands have a de facto moratorium for new plants. Several countries like Austria, Denmark and Ireland have renounced nuclear power entirely, even though they need more electricity generating capacity. Against these negative trends, France, Japan and Soviet Union remain the expanding nuclear power programmes.

Also there are some elements to be taken into account for prospecting the future.

During the seventies and the eighties, it was possible to meet relatively slow increasing demand for electricity. However, this is no longer the situation in many countries. Already economic recovery in a number of OECD countries is resulting in higher forecasts of electricity demand growth with expectation to increase by 2.3 % a year until the year 2000. Those countries without any surplus capacity to generate electricity or electricity importing connection could find themselves in a difficult situation due to a pressure of demand in the comming future. New plants need to be ordered to meet demand.

Another indicator is the changing atomosphere toward nuclear power. The scepticism about nuclear power which reached its full expression after the Chernobyl accident is beginning to be somewhat offset by an increasing awareness of the serious environmental consequences of the current levels of use of fossil fuels. The greenhouse effect of a warming world atmosphere but also acid rain, and other impacts, are now seen by many scientists and policy makers as a real threat, and it is becoming more widely realized that, apart from hydroelectric power, nuclear power is seen more and more as one of the most feasible sources now available to generate electricity in the quantities needed and with the requisite reliability without producing any of the greenhouse gases.

However, although there are strong reasons for nuclear power, opposition is still strong. The main arguments are; the risk of proliferation of nuclear weapons, the risk of accidents with serious consequences, problem of radioactive waste disposal, which loom large in the public mind. It is realized today that these issues together with others to be taken into account are now international.

Non-proliferation:

The Atoms for Peace programme which led to the creation of the International Atomic Energy Agency within UN sysytem was based on the philosophy that technology, material and equipment would be made available against commitments that they would only be used for peaceful purposes. The verification that these commitments are upheld is now being provided through the IAEA safeguards system, the first on-site inspection system. Some 95 % of all fissionable material outside nuclear-weapon States is under safeguards control. The fears which were common a quarter century ago that many States would acquire nuclear weapons have not materialized. The risk of proliferation exists, but the IAEA would have the ability to verify that no use for weapons purposes is made of any nuclear facility or fissionable material submitted to its safeguards.

Safety:

The TMI and especially the Chernobyl accident have increased the attention in many countries to the safety of nuclear reactor operations not only at home but also in other countries. A nuclear accident anywhere in the world would have considerable psychological consequences, even if the physical fallout were to be negligible.

An extensive international role would be required a considerable apparatus. The international community seeks to give good models for national safety regulations and assistance and support to regulators and plant operators. This regime is expected to be effective, not because regulators, suppliers or operators are legally obliged to respect it, but because they find it in their interest to respect it and rely on it.

Already in the early 1970s, the IAEA served as an instrument for building an international consensus on safety standards and practices. The Nuclear Safety Standards Programme - the so-called NUSS - produced 5 Codes of Practice covering the essential safety aspects of governmental organization, siting, design, operation and quality assurance. The code are supplemented by 56 Safety Guides recommending how these safety requirements could be implemented. They have been updated to reflect current thinking and experience gained in accident prevention and management, and major advances in the state of the art.

The Agency's International Nuclear Safety Advisory Group (INSAG) has issued a set of Basic Safety Principles for Nuclear Power Plants, establishing comprehensive safety targets for existing and future plants. These targets, which are more demanding than current regulatory standards, have been well received by the nuclear communities around the world and will undoubtedly exert influence on operators, designers and regulators.

While standards and regulations are indispensable to ensure nuclear safety, they are not enough. Equal attention must be paid to operational safety in the some 430 nuclear power plants which are now operating in the world and some 100 plants which will soon be put into operation. To assist its Member States in this regard, the Agency is offering several services which are being increasingly used.

They are the OSART (Operational Safety Review Team) programme to review operational safety of nuclear power plant, the ASSET (Assessment of Safety Significant Event Team) programme to assess safety significant events and define the real root causes, the arrangement for reviews of regulatory organizations by peers from other countries, and the IRS (Incident Reporting System) for the broadest possible information exchange.

The ERS (Emergency Response System) corresponding to the international agreements which were reached after the Chernobyl accident on measures that are designed to contain and mitigate the consequenses of an accident, notably early notification (now signed by 42 parties) and assistance (now signed by 37 parties) in the case of radiological emergencies. Also here to be mentioned is that all nuclear power plant operating in the world have jointly set up the World Association of Nuclear Power Operators (WANO) with the aim to share the affluent experience and thereby further enhance safety. The IAEA has welcomed this initiative and co-operate with WANO.

As seen above, so much of international action is related to nuclear safety of existing nuclear power reactors.

New Generation Reactors:

Considerable thought and discussion is also devoted to the development of nuclear thechnology - both that which can be backfitted to existing plants and that which will give the world new types of nuclear power plants.

To the new generation of nuclear power reactors, several observations have emerged.

First, in many countries, critical examinations of past operating experiences have led to the evolution of requirements for these new generation reactors. For the most part, the requirements have been developed by the actual users of nuclear power, i.e. utilities, and specify the minimum standards that these users believe are necessary to assure the safe, reliable and economic operation of future nuclear systems. Two types of advanced nuclear power systems appear to be evolving.

The vast experience that has been gained from existing reactor types allows an evolution of these types, simplifing design and operation, enhancing safety, reducing size and allowing standardization. Building as they do on proven and tested technology, these reactors can be available in the first half of the 1990s. They should be competitive with coal-burning power plants and have a construction time of about four years.

A number of new reactor designs exist or are emerging which differ considerably from the currently used types with standardized and simpler design, more "passive" safety features and often smaller sizes. Through lower total capital costs these reactors could help to improve the management of investment risks. Such features might also make them interesting for some developing countries.

Second, since the technology of these reactors has often not been tested, they may in many cases have to be built first as prototypes, from which experience can be gained. A way of reducing the cost of development would be for several countries and industrial suppliers to share the expenses of designning and building prototype. Whether such an internationalization would be possible regarding a technology development that may have a very early commercial use is as yet an open question. From the Agency's side , we are seeking to promote renewed co-operation on this subject between governments and industry, also internationally.

Third, in the work toward a fusion reactor, internationalization has been highly successfull in the first conceptual design phase of the International Thermonuclear Experimental Reactor or ITER project carried out under IAEA auspices. Here, however, commercial use is a number of decades away.

Fourth, the institutional framework surrounding nuclear technology has become very important. The licensing process must be predictable and reliable, the rate setting for electricity must be such that investments may be profitable, the social climate must be such that fuel can be transported, spent fuel stored and waste safely disposed of.

Radioactive waste Management:

There is some misunderstanding in the public that viable methods do not yet exist for the safe disposal of high level radioactive waste. Responsibility for correcting this view lies mainly with national governments and authorities. However, an increasing number of international activities related to radioactive waste disposal are being pursued through the Agency.

The physical and technical aspects of waste disposal have long been the subject of international co-operation and there is no uncertainty in the nuclear communities about the technological ability to achieve safe disposal of all radioactive waste, including high level waste.

International consensus exists that several options are available for the safe disposal of low and intermediate level radioactive waste, and a number of actual repositories for this kind of waste are presently in operation.

Last November, the IAEA published Safety Series NO. 99, Safety Principles and Technical Criteria for the Underground Disposal of High Level Radioactive Waste. This document is the first to be issued at the level of an Agency Safety Standard in the area of waste disposal for high-level waste, and is intended to form a common basis for the development of more detailed and quantitative performance criteria both at the national and international levels. It should be noted that in devising standards for the disposal of any radioactive waste, one principle has consistently been that the waste disposal shall take place in such a way that both present and all future generations shall be protected against any radiation risks higher than we would accept today and that the burden of waste disposal should not be left to future generation.

The uncertainty that the nuclear power industry faces about waste disposal relates not to waste packages or the existence of geologically suitable disposal sites, but rather to the ability of societies to reach decisions in these matters. The chairman of the IAEA's INSAG succinctly expressed this thought by saying: "The 'unsolved' problem of radioactive waste is more political than technical and will require more guts than brains to solve."

In the area of radioactive waste management the Agency provides advisory services to its Member States. In 1987 the Waste Management Advisory Programme (WAMAP) was established to assist developing Member States in establishing national waste management programmes based on sound safety and radiological protection principles and practices. Under WAMAP, 23 developing countries have been visited by expert teams to provide advice and assistance on waste processing, storage and disposal projects. Emphasis is placed on making the linkage between use of the atom and the resulting need to safely plan, manage and dispose of the resulting waste streams. As a complementary programme to WAMAP, the Agency recently established the Waste Management Assessment and Technical Review Programme (WATRP). This new Agency service is being offered to Member States with well-established waste management programmes. WATRP has been developed to formalize the mechanism by which the Agency offers technical assessments and peer reviews of waste management policies, concepts or programme activities of Member States by an independent international panel of experts. The WATRP programme thus offers assistance in the evaluation of the technical, operational, safety and performance features of waste management systems planned or in operation, by providing an independent peer review of such systems or activities.

Environmental Concerns:

The first rude awakening at the political level to the global environmental threats came when it was confirmed a few years ago that the earth's ozone layer had been damaged through the use of chlorofluorocarbons (CFCs). A convention was drawn up in 1985 followed by a specific protocol to commit specified reductions in the production of CFCs by the late 1990s.

The awakening which was prompted by the ozone problem has been transformed into a full alert by the fear of global warming.

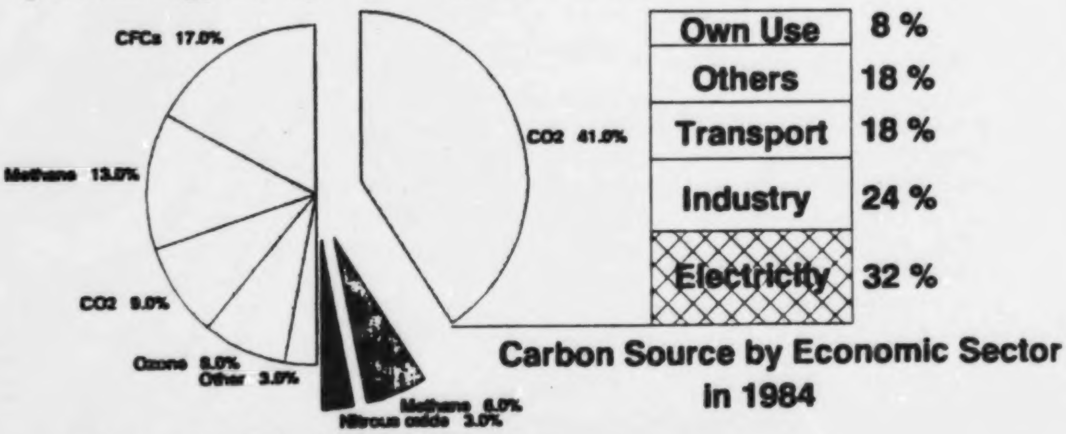


Fig. 8. Global warming sources

The relevant scientific community now estimates that about 17 % of the greenhouse effect is caused by CFCs, 19 % by Methane and 50 % by CO2. And 32 % of total CO2 emisions comes from the electric power sector as shown in the Fig. 8.

THe CFC problem is already being tackled by the agreements. Methane is a very strong greenhouse gas. Its sources are mainly ruminating cattle, rice paddies and marshlands, but methane also escapes in the production, distribution and use of natural gas. The methane which results from the production of staple foods is hard to avoid and these emissions can even be expected to increase if population and food production increase. The additions to the atmospheric content of CO2 come mainly from the use of fossil fuels. The present emissions from these sources are some 20 Giga tons per year. An estimated additional 5 Giga tons per year come from the destruction of tropical rain forests.

Since there is no economically viable way in which CO2 can be eliminated in the combustion of fossil fuels, any action to reduce CO2 emissions would have to involve limitation on the use of fossil fuels or a shift between them. The burning of oil produces less CO2 than coal per unit of heat generated. Natural gas is even more advantageous from this point of view but the leakage problem might offset some of the gains that would result from a large-scale fuel-switching from coal to gas. Afforestation would be certainly be beneficial but its effects would be slow and it would necessarily involve vast surface areas.

Only through international action it can be hoped to reduce or contain global CO2 emissions. One of these actions will have to involve limiting the burning of fossil fuels. What might be agreed upon in international fora, however, might not be easily accepted by national governments due to a variety of reasons. Belgium recently opted for a gas-fuelled power plant rather than a nuclear one. Sweden seems intent to phase-in gas and phase-out nuclear. Italy, having already stopped its nuclear power plants, is planning a much greater use of coal and gas. China plans to double its coal production between 1985 and 2000. India plans to treble its coal use over the same period. All this will increase CO2 emissions. The current per capita CO2 emission is 2 tons per year in China and 0.9 tons in India. This compares with 12.3 tons in the US and 10.5 tons in the FRG. Suggestions that energy-hungry developing countries like China and India should freeze their CO2 emissions at current low levels are hardly realistic.

After the oil shocks there was continued economic growth in industrialized countries without increased primary energy use but with increased electricity use. This showed the potential which existed for energy conservation by both more efficient and more discriminate use of energy. There may be significant potential for conservation of both primary energy and electricity, especially in high consumption countries, however, this will not be enough to offset the increasing global energy demand which we can expect in the near and intermediate future.

For an expanded use of renewable energy sources, apart from hydro power, geothermal energy now contribute some 0.1 % of the global energy supply. Solar and wind energy have so far only contributed in some nickes to the energy supply mix.

Much work is needed to reduce the costs of solar and wind generators considerably to become economically competitive to centralized large scaled power plants. The International Energy Agency (IEA) in Paris has stated that the contribution of renewable energies, besides hydro power, in most of the IEA countries for the year 2010 can be estimated to be a maximum of 5%. The World Energy Conference suggested, in a study made public last year, an even lower figure: 3 % by 2020. This does not negate the fact that these energy forms can be very important in specific regions or applications. But they suggest that it would be irresponsible to count on major global contributions from energy systems that have so far not turned out to be viable on a large scale. It is hardly realistic to suggest that they can replace fossil-fired plants to any major extent during the next decades.

There are now only two energy sources which are technically and economically proven on a large scale and which can produce large amounts of energy without adding significantly to SO2, NOx or CO2 emissions. These are hydroelectric power and nuclear power. There is still a very large hydro capacity in the developing world, and this should certainly be used where environmental concerns can be met. In industrialized countries there is a limited exploitable potential left.

This leaves us with nuclear power. Nuclear power is already contributing to avoid significant volumes of CO2 emisions. A strong expansion could assist to avoid even more CO2. To support this idea, let us consider two "experiments of thought" which have their realistic background in the industrial potential for an enhanced nuclear programme. It could be assumed that by 2010, nuclear power programme would avoid on global level some 20 % of the CO2 emissions that were emmitted if coal would be used for electricity generation instead based on the assumption that the trend of the 1989 - 2000 nuclear power programme to continue up to 2010 (case 1), and if nuclear power programe were accelerated to expand with nuclear power starting up by 40 GWe per year as from 2001 until 2010 (case 2), avoided CO2 emissions would reach 36 % by 2010.

Table 3. Avoided CO2 emissions due to Nuclear Electricity

Year	1988	2000	2010
Case 1			
CO2 avoided (million tons of C)	438	660	867
Percentage reduction	21	21	21
Case 2			
CO2 avoided (million tons of C)	438	660	1,307
Percentage reduction	21	21	36

[Source: Ref. 5]

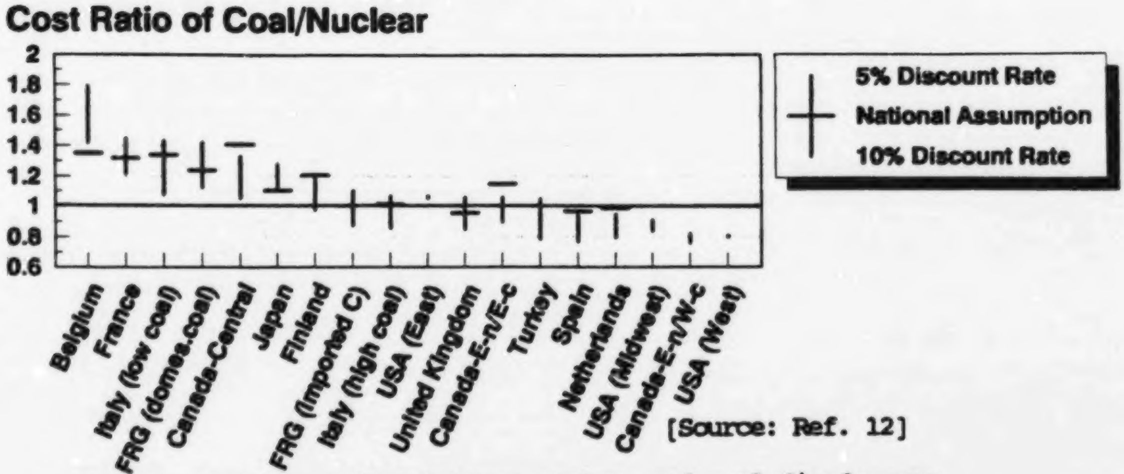
Informatively, the Agency will convene a Senior Expert Symposium on Electricity and the Environment jointly organiged by 11 international organizations 13 - 17 May 1991 in Helsinki. The objective of the Symposium is to assess the potential role of different means of meeting electricity requirements, considering both demand and supply sides options in light of their comparative economic, environmental and health related impacts, and to suggest a framework within which these considerations should be taken into account in the planning and decision making process for electricity production and use.

Other issues

Public information: In countries using nuclear power, various organizations have been involved in public information campaigns for nuclear energy, however, after the Chernobyl accident heightened public concern on nuclear risks has had a direct and strong influence on nuclear programmes. New feature of these days is found to be the desire by the public to be involved in deciding on the key directions of policy development. Energy decisions are no longer the sole domain of governments and industry. For public information, the dispassionate informer's role should be sought with the ambition to provide factual, correct and verified information. Nuclear power's future contribution to energy needs will depends to a considerable extent on the nuclear communities success in reducing the public concern about safety and in restoring public confidence in the ability of nuclear energy. The ability to explain the main features of a particular technology and why it is needed to the general public therefore recquires a much greater dimension.

In this task, the ability to translate the language of technicians, which is always difficult to understand, into simple and easy-to-understand but correct language is of crucial importance. The Agency has been devising information and experience exchange opportunity to informers on public information activities covering all aspects of nuclear energy, and will strengthen its capacity in this field this year by a special contribution from Japan.

Economic competitiveness: The economic situation of nuclear power is now widely different in different countries for a variety of reasons. The problems of costs to a great extent are institutional, depending, e.g. on the situation and regulation of the industry and interest and discount rates.



[Source: Ref. 12]

Fig. 9. Cost comparison between nuclear and coal-fired power (commissioning in 1995 - 2000)

A recent joint study by the Nuclear Energy Agency (NEA), IEA/OECD and IAEA pointed to the increasing costs of nuclear electricity and the stable costs of the main competitive fuel, i.e. coal. The study still shows that the future nuclear plants would have an advantage over coal-fired plants in many countries in the OECD and also in some developing countries with established nuclear power programmes (Fig. 9).

Conclusions

1. The availability of energy is essential for the world economy. The demand for energy of the world will continue to increase as the world economy develops in the foreseeable future. Recent democratic movements in Eastern Europe will push or accelerate the increasing world energy demand even further.

Electricity is the inevitable energy form for both developing countries and industrialized countries with its convenience, efficiency and overall versatility for civil lives and economic activities. Increasing demand of electricity is thus the logical future development.

Electricity growth rates, higher than both population and total energy consumption growth rates are expected to continue , and its one-third of today's share of electricity in the energy use could be expected to increase further.

2. Developing countries sharing three-fourth of the world population are rapidly increasing their energy demand to improve their economies and nations' living standards. It is completely unrealistic to expect that they will be able to limit the use of the energy sources such as oil, gas, coal or wood, available and easy to handle.

It is clear that , not only from the global energy security point of view but also from the global environmental point of view, they will assume growing importance in the global energy supply policies and energy security in the world.

3. Rapid depletion of the world's natural resources is foreseen if such recources continue to be the primary means of generating electricity and the environmental impact of much use will definitely significant.

Since the development of energy requires conceivable long lead-time, structuring the balanced energy supply mix should be based on the long term prospects of world energy/environmental evolution.

4. In these context, nuclear power will remain an irreplaceable element in both in the world energy/electricity supply mix, and in the global environmental protection. The development of the nuclear option should rest on a realistic perception of the future global energy scene.

In this regard, specific efforts need to be made to take into account the implications of public awareness on the nuclear safety, reliability, competitivity and the necessity of nuclear option.

As an international body, the Agency will continuingly play an instrumental role in assisting of structuring the world energy/electricity supply mix from the global point of view.

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A HYDROGEN BASED ECONOMY

Presented by

Richard D. Champagne
President Chief Executive Officer
Hydrogen Industry Council
Montreal, Quebec

ENERGY AND ELECTRICITY: A CONFERENCE ON ELECTRIC POWER PLANNING IN THE 1990s
Montreal, Quebec
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Let me start first by giving you a few examples that will clarify your understanding on how we view Hydrogen in the long term future.

Computers and the telephone system require electricity but are not influenced by whether the electricity is made from coal, nuclear or hydraulic sources. A jumbo jet flying to Europe drinks turbo fuel, but does not care if it is made from conventional crudes or oil sands bitumen. Currencies, not sources, characterize the products and processes which use energy

In the long term, energy transactions will be dominated by the currencies hydrogen and electricity. It is more difficult to name the energy sources which will be used to manufacture these currencies. But, much more than the unpredictable sources, the predictable currencies electricity and hydrogen will shape the world's future.

(SLIDE 1)

The major reasons for the move to the hydrogen age are:

1) The world's high quality fossil fuel reserves are being depleted. It is not that we will run out of oil, or coal, or oil sands, but that the remaining reserves will be lower in quality and more difficult to extract, leading to higher production costs and the potential for increased environmental damage. The problems associated with fossil fuels will encourage a move ,toward sustainable sources.

(SLIDE 2)

2) The environment is another force driving the move to sustainable energy sources. The impact of fossil fuels is well known for the production of acid rain and smog. But the

world now faces and additional environmental issued without precedent - the prospect of global climatic change, often called the greenhouse effect, brought about by the increased levels of carbon dioxide in the atmosphere. Fossil fuels probably contribute most to the greenhouse effect, although it is aggravated by other industrial emissions and worldwide deforestation. There is little possibility our world can avoid a mean global warming of at least 2°C by mid 21st century. This warming will be accompanied by substantial regional climatic changes, interrupted food production cycles, and regional droughts. In the long term, coastal regions which include most of the world's great cities could be affected by rising ocean levels. Even with aggressive moves to reduce CO_2 emissions beginning at the turn of the century, atmospheric CO_2 concentration will have doubled since pre-industrial revolution days by 2050. And so, long before we "run out" of fossil fuels, the world must move to sustainable sources which do not dump CO_2 wastes into the atmosphere.

(Slide 3)

3) All sustainable energy sources can be used to manufacture either electricity or hydrogen. Both are renewable in the true sense of the word. Electricity, which may be viewed as an electrical charge separation, returns to a charge neutrality when it is used. Hydrogen, which in this context may be considered " water separation," returns to water when it is used. This renewability is the essential quality that removes all negative environmental impact - things end up the way they were. And, of course, it lays to rest the question of "running out" - we can no more "run out" of hydrogen than we can "run out" of electricity.

(Slide 4)

4) Today's fossil sources (solid, liquid or gaseous) are the only sources of chemical fuels. Moreover, fossil sources are used for many chemical commodities. Therefore, sustainable energy sources must manufacture a currency to substitute for gasoline, turbo and other transportation fuels. Hydrogen is the only chemical currency which can be manufactured in necessary quantities by all sustainable sources, world wide. The question has been asked many times - "Is there another option?" None have appeared. It is a remarkable stroke of fortune that this single option has so many attractions.

Among today's sustainable sources, hydraulic is the most important throughout Canada, although nuclear plays an equal role in Ontario. Unlike Canada, nuclear is much more important than hydraulic in most developed nations. If the growth of conventional nuclear fission is slowed (due in part to the Chernobyl accident), then the move to sustainable technologies may be temporarily delayed - while improved fission and others sustainable technologies are developed. But it is the emergence of sustainable sources, not which ones dominate, that is important.

One last question may remain. If we accept that we must eventually use sustainable rather than fossil sources, and that these sources can manufacture electricity, we might ask: Why not do everything with electricity? One answer is, of course, that electricity is not storable and is not a material - electricity cannot be used to fly an airplane. But perhaps and even more important response is: Why would we want to do everything with electricity - when hydrogen is available, and when electricity and hydrogen work together so well?

(Slide 5)

To understand how hydrogen and electricity will share tasks, it helps to know how they complement each other:

1) Hydrogen can be stored in enormous quantities; electricity cannot.

(Slide 6)

2) Electricity can transmit energy without moving material; hydrogen cannot.

(Slide 7)

3) Hydrogen can be a chemical or material feedstock; electricity cannot.

(Slide 8)

4) Electricity can process and store information; hydrogen cannot.

(Slide 9)

5) Transportation of hydrogen can match the continental and inter continental distances of natural gas and perhaps the worldwide movements of oil; transmission of electricity is more limited.

It is apparent that these two currencies are complementary, and can satisfy the consumer and industrial needs of the future. Electricity will continue to be used as it is today: for illumination, for information processing, for fixed-route high-frequency transportation systems like subways, high density trains, and perhaps, in the long term, high speed vacuum tube vehicles. Hydrogen will be the currency of choice for most activities now satisfied by liquid fuels. Airplanes will fly on hydrogen, free-range vehicles like cars and snowmobiles will be fuelled by hydrogen, as will trains. And hydrogen will be used in the production of man-made materials like fertilizers and plastics.

Because electricity has been with us for almost a century and now profoundly shapes our lifestyle, we are familiar with electrical technologies. Although computers, television sets, and home videos will undoubtedly enjoy further development and many new electricity-fuelled products will be introduced, most can be imagined as some evolution of today's products.

On the other hand, the technologies and products using hydrogen, for flying airplanes and powering the car for the drive to the cottage will, generically, be very different from the technologies which perform these tasks today. Just as a horse did not resemble an electric motor when electricity substituted for hay in pulling streetcars, the generic propulsion systems of hydrogen automobiles are unlikely to resemble the internal combustion engine of today's Chevy. Even those heat engines which are hydrogen-fuelled will bear little resemblance to today's heat engines. For example, engines for hypersonic hydrogen-fuelled commercial aircraft will differ greatly from today's aircraft engines.

Some tasks could be served by either hydrogen or electricity. Space heating is a good example. It could be done by electricity as it often is today, or by hydrogen. Hydrogen could be combusted on, for example, catalytic baseboard heaters with some emitted water vapour contribution to humidification and any excess condensed. Since no chimney would be needed to vent the products of combustion, all the hydrogen's energy could go to heating rather than losing some of it up the stack as in today's oil and gas furnaces. Moreover, unlike electricity, hydrogen has few load-levelling demands. On the other hand, electric heat pumps provide heating and cooling very efficiently and this technology will continue to improve. Therefore, it is difficult to predict whether electricity or hydrogen will win for keeping us warm. Probably both will have their niches. And a camper can still have a wood fire.

This discussion of the "currency choice" applies to services we understand today. Although it is commonly said that "necessity is the mother of invention," the reality is more often that "invention is the mother of necessity." History shows that when an energy currency is introduced, many new technologies are invented, grow into widespread acceptance and then become essential. A hundred years ago people would not think a telephone essential, although the forward looking mayor of one American city was delighted to say he could "visualize a day when every city would have one." Today's essential telephone technology could not even be imagined before people began experimenting with electricity.

In this spirit, it is difficult in 1990 to speculate on the technological marvels which will emerge as civilization begins to use hydrogen in everyday life. But that there shall be a new set of hydrogen products is certain - because hydrogen has properties almost as unique as electricity - and imaginative people will think of ways to develop products which exploit these properties.

(Slide 10)

The hydrogen and electricity age will have five additional characteristics.

- First, the world will be cleaner. Cities in particular will be environmentally better place to live. The smog, most carcinogenic emissions, and many other pollutants that are associated with large cities could be largely eliminated.

(Slide 11)

- Second, compared with today's petroleum-based technologies, hydrogen technologies will generally (1) be more efficient, (2) last longer and require less maintenance, and (3) have a higher purchase costs which are offset by lower life-cycle cost. These characteristics will be in phase with the move away from the "throw-way" society, a trend we see beginning today. The world will have evolved from a pre-industrial age "conserver society" (required by poverty), through to the "throw-away" society (in the first blush of technology produced abundance) and then back to a "conserver society" (using efficient, high quality, long lasting products.

(Slide 12)

- Third, the importance of electrochemical energy conversion technologies will grow, perhaps to eclipse today's ubiquitous heat engines. All living things convert their fuel (food) to work - for growing, running, swimming or flying - by electrochemical processes. But about two centuries ago when mankind first invented machines to convert fuel to work, the electrochemical way of nature was not copied. Rather, heat engines were invented, of which the first example was the steam engine. Electrochemical energy conversion is inherently more efficient, although it characteristically suffers from low power densities compared to heat engines. Hydrogen is particularly suitable for electro-chemical devices and its availability will no doubt lead to the development of high energy density technologies.

(Slide 13)

- Fourth, hydrogen will do more than just substitute for today's fossil fuels. Hydrogen will truly work together with electricity. Electricity can easily be converted to hydrogen. Hydrogen can easily be converted to electricity. The two currencies are fully interchangeable, which is not true of today's currencies. Today, electricity can be made from fossil fuels, but gasoline cannot be made from electricity.

(Slide 14)

- Fifth, in the far future, some predict most of the world's energy will come from a small number of huge central sources. These sources could be solar stations in the Sahara or on floating platforms in the south Pacific, or nuclear fusion plants in remote locations. Hydrogen can be made directly from these sources without going through an intermediate electricity step. Hydrogen will then be the dominant first-stage currency because, compared to electricity, its delivery and storage flexibility will allow it to become a global trading commodity. Electricity will normally be manufactured locally, perhaps on demand from hydrogen using fuel cells. Thus, the far future may properly be called "the hydrogen age."

Perhaps the most important thing is yet to be said. Knowing that the hydrogen age is approaching can do much to remove fear for the future. If civilization can avoid nuclear war, hydrogen and electricity can offer a brighter 21st century. Brighter skies. Brighter work conditions. Brighter quality of life.

(Slide 15)

When will the Hydrogen Age be here?

there are several ways to examine this issue.

First, we can look at the evolution in the mix of energy sources to estimate when sustainable sources will provide more energy than can be absorbed by the electricity market. Based on this analysis, hydrogen produced from a sustainable energy is expected to begin being manufactured in significant quantities at about the turn of the century.

Second, we can examine the evolution in the hydrogen/carbon (H/C) ratios of the currencies used by civilization over the past 150 years. This shows a steady progression to increasing H/C ratios, and again indicates significant quantities of pure hydrogen use about 2000-2006, with growing use thereafter.

Third, we can note the rise in the CO_2 content of the atmosphere. While this approach is less amenable to formal analysis, it does appear reasonable to expect world political action to reduce CO_2 emissions around the year 2000.

So, by the middle of the next century, it is reasonable to expect that nearly half the primary energy will be provided from sustainable sources, with the rest from fossil sources. The predominant fossil source is expected to be natural gas. Oil and coal can be expected to be mined primarily for their carbon content, and through the extensive use of hydrogen addition little CO_2 will likely be rejected when they are used to manufacture what we now describe as "petroleum products." Consistent with these estimates, it might be reasonable to assume that by mid-century the currency market will be divided roughly into thirds: One third electricity, one third liquid hydrocarbons, and one third hydrogen. About two-thirds of the hydrogen will probably be produced from natural gas, and the rest from sustainable sources.

After the mid-21st century, energy sources which have not yet been imagined may emerge. One or more of these could, in time, become more significant than any of the sources we now use or are developing. But the uncertainty on long term sources does not carry over to currencies. No logic we can construct leads to a new set of energy currencies emerging after electricity and hydrogen are fully adopted.